FILED
10-03-14
04:59 PM

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	)))	Rulemaking 13-12-010 (Filed December 19, 2013)

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) PROPOSED CHANGES TO ITS ASSEMBLY BILL 57 BUNDLED PROCUREMENT PLAN

PUBLIC VERSION
(Confidential Appendices E, F, and J
Public Appendices A, B, C, D, G, H, I, K, and L)

WILLIAM V. WALSH
AMBER WYATT
MELISSA HOVSEPIAN

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-6054
Facsimile: (626) 302-6962
E-mail: Melissa.Hovsepian@sce.com

Dated: **October 3, 2014**

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I.

EXECUTIVE SUMMARY

Southern California Edison Company (SCE) submits this filing to support its Proposed 2014 Assembly Bill (AB) 57 Bundled Procurement Plan (BPP) in Phase 2 of the California Public Utilities Commission's (CPUC's or Commission's) Order Instituting Rulemaking (OIR) 13-12-010, also known as the 2014 Long-Term Procurement Plan (LTPP) proceeding. The Commission opened the 2014 LTPP to consider, among other things, the Investor-Owned Utilities' (IOUs') proposed updates and modifications to their AB 57 BPPs. In the Scoping Memo and Ruling of the Assigned Commissioner and Administrative Law Judge issued on May 6, 2014 (Scoping Memo), the Commission defined as "in scope" the following issues for the AB 57 BPPs:

1. Maximum and minimum limits on IOU forward purchasing of energy, capacity, fuel, and hedges;
2. Specification of the products that the IOUs can purchase;

3. Specification of rules that, if followed, would exempt the IOUs from reasonableness review; and
4. An integrated plan to comply with state policies, including the Loading Order.[1]

SCE submits this filing and accompanying Proposed 2014 AB 57 BPP and Appendices[2] in accordance with the OIR and Scoping Memo. SCE provides a description of the purpose and scope of the IOUs' AB 57 BPP framework in the Overview of its Proposed 2014 AB 57 BPP.[3] The 2010 LTPP proceeding was the last time the Commission approved the IOUs' BPPs in Decision (D.) 12-01-033 and D.12-04-046. This filing does not directly address elements of SCE's AB 57 BPP that the Commission had previously approved in SCE's 2010 Conformed AB 57 BPP and subsequent advice letters modifying it, which are currently in effect.[4] Rather, SCE's filing supports SCE's proposed updates and modifications to its existing AB 57 BPP authority.[5] SCE requests that the Commission approve the following changes and clarifications, as reflected in the accompanying Proposed 2014 AB 57 BPP and Appendices:[6]

- Clarity in the descriptions of: (1) SCE's existing authorized preferred resource products (Energy Efficiency (EE), Demand Response (DR), and Distributed Generation (DG)) to more closely align with developments and commonly-used terms in the industry; (2) additional outreach efforts to preferred resource bidders

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1 Scoping Memo, at 11.
2 Attachment B and Attachment C respectively.
3 *See* Attachment B, at Sheets 1-2.
4 See Attachment C, Appendix K, at Sheets K-1 and K-2 for a description of SCE's 2010 Conformed AB 57 BPP and subsequent advice letters.
5 The discussion below in this filing is limited to substantive changes in SCE's AB 57 BPP and Appendices. SCE also made structural and ministerial changes to improve the quality and clarity of the documents. A summary of all changes is provided in Attachment A.
6 Attachment B and Attachment C are submitted in the form of a conformed tariff sheet filing to accurately reflect the upfront standards and criteria that SCE proposes for adoption by the Commission. If adopted in a Commission decision in the LTPP, SCE will subsequently submit its AB 57 BPP and Appendices as a conformed filing via advice letter, which is discussed in more detail in Section IV.E.2 below.

on participation in an All-Source Request for Offers (RFO); and (3) how the existing valuation methodology can appropriately account for the differing attributes of resources, including preferred resources;

- Authority to enter into transactions with Eligible Renewable Resources (ERRs) for terms of less than five years consistent with the other applicable upfront and achievable standards of its AB 57 BPP in furtherance of the Loading Order;
- Update to SCE's ratable rates and position limits, as calculated in SCE's bundled need analysis (BPP Analysis) based on the Commission's Trajectory Scenario;
- Change to the Customer Risk Tolerance (CRT) calculation methodology used for determining the consultation requirement with SCE's Procurement Review Group (PRG) regarding hedging activity;
- Addition of Resource Adequacy (RA) Sales as a non-standard product due to its unique circumstances;
- Authority to use brokered transactions for greenhouse gas (GHG) compliance products, as the market for such has evolved;
- Change to the linkage rule adopted in D.14-02-040 to reach a compromise between competing objectives of the "least-cost, best-fit" (LCBF) methodology and the prohibition on multiple deals that, if evaluated as a single medium-term transaction, would exceed BPP authorization;
- Streamlined process for updating all of SCE's rates and limits through one advice letter filing in years where it does not submit an AB 57 BPP in the LTPP; and
- Streamlined process for the conformed advice letter filing once SCE's AB 57 BPP is approved in this proceeding.

II.

ENHANCEMENTS TO FACILITATE PARTICIPATION OF PREFERRED RESOURCES IN SCE'S AB 57 BUNDLED PROCUREMENT

One of SCE's top priorities in its Proposed 2014 AB 57 BPP is to present an integrated plan that complies with state policies, including the Loading Order, as directed by the Scoping Memo. SCE remains committed to procurement that is consistent with the Loading Order. In the 2010 LTPP cycle where the IOUs' 2010 BPPs were approved in D.12-01-033, the Commission clarified its policy on implementation of the State's "Loading Order," as provided in the Energy Action Plan (EAP) II:[7]

> . . . [W]e expressly endorse the general concept that the utility obligation to follow the loading order is ongoing. The loading order applies to all utility procurement, even if pre-set targets for certain preferred resources have been achieved.[8]

In other words, the Commission expressed in D.12-01-033 that the IOUs' ongoing obligation to adhere to the Loading Order includes their residual bundled procurement activities (*i.e.*, remaining procurement to meet bundled customer needs after accounting for the IOUs' existing resources, including planned preferred resources) pursuant to the AB 57 BPP framework.

Since that decision, SCE has further identified through the 2012 LTPP's Local Capacity Requirements (LCR) RFO process, that there are some circumstances in which a preferred resource might also compete and be the successful bidder in an all-source RFO process for residual bundled need procurement.[9] Consistent with this direction, SCE proposes in this LTPP

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[7] "The loading order identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs. After cost-effective energy efficiency and demand response, we rely on renewable sources of power and distributed generation, such as combined heat and power applications." *See* Energy Action Plan II –Implementation Roadmap for Energy Policies, Oct. 2005, at 2, *available at* http://docs.cpuc.ca.gov/published/REPORT/51604.htm.

[8] D.12-01-033, at 20; *see id.* at Ordering Paragraph (OP) 4 ("Utility procurement must comply on an ongoing basis with the Commission's loading order.").

[9] In the LCR tracks, discussion of the ability of Loading Order resources to compete within an all-source LCR RFO took place within the framework of new resources capable of meeting a local area reliability need that would receive contracts with terms in excess of the less-than-five-year contract

Continued on the next page

cycle to clarify and enhance the upfront standards and criteria in its 2014 AB 57 BPP to continue to foster participation of Loading Order resources[10] in SCE's "All-Source" RFOs for transactions less than five years in duration. SCE requests approval of (1) certain clarifications to SCE's existing authorized preferred resource products and processes and (2) a new product for ERRs so that transactions can be submitted through SCE's Quarterly Compliance Report (QCR) process without Commission approval. These changes should further facilitate competition amongst all resource types within the All-Source RFOs conducted pursuant to SCE's AB 57 authority.

The All-Source RFO is most suited to procure existing generation resources that are not otherwise under contract. As discussed in further detail below, with the approval of the new product for ERRs and additional clarifications in SCE's AB 57 BPP, there will be potential for participation and competitive selection of preferred resources in SCE's residual procurement activities.[11] As such, beyond the dedicated preferred resource programs in other proceedings, preferred resources would have the opportunity to compete head-to-head with conventional resources in meeting SCE's residual procurement needs.

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duration authorized under the AB 57 BPP framework (*i.e.*, approval of any such LCR contract would require an application and Commission approval, unlike the "pre-approved" AB 57 framework under the Quarterly Compliance Report process). *See* D.12-01-033, at 47, Finding of Fact (FOF) 24 ("The Commission currently limits pre-approval of bundled procurement contracts to 'less than five years.'").

[10] The EAP II Loading Order does not address energy storage resources. Therefore, SCE's proposal for its residual bundled procurement does not address energy storage at this time. However, SCE remains supportive of efforts to further integrate energy storage resources into its procurement activities, including the Energy Storage OIR, the LCR track of the LTPP, and SCE's Preferred Resource Pilot. SCE would be open to consideration of how to integrate energy storage into residual bundled procurement activities in this or future LTPP cycles, recognizing that energy storage devices can shift demand from peak periods.

[11] As explained in further detail below, there is some potential for existing renewable resources to be a competitive alternative in an All-Source RFO. For example, a short contract duration could serve as a bridge to a longer-term contract. Contract durations shorter than five years may also be beneficial and attractive to certain resources such as DR and EE where limited investment is needed to provide the reduction in load but are not likely sufficient to site, license, and build a new solar, wind, or other eligible renewable resource.

A. Clarification of Existing AB 57 BPP Product Definitions and All-Source RFO Processes for Preferred Resources

SCE currently has authority in its AB 57 BPP to procure certain preferred resources in the Loading Order – EE, DR, and DG products.[12] These categories of authorized products, however, require further clarification to reflect how the market has evolved and technology advancements. SCE describes the specific changes in Appendix A of SCE's Proposed 2014 BPP.[13] These changes are clarifications to SCE's approved AB 57 BPP. They provide more common product definitions that have evolved within the market.

The clarified products will further enable SCE to procure EE, DR, and DG to meet SCE's residual bundled procurement need within the context of its AB 57 BPP. SCE's LCR RFO has demonstrated that EE and DR suppliers can be responsive to an all-source solicitation when product definitions and performance requirements are well-specified in the solicitation process.

Similarly, through SCE's LCR RFO process, SCE has developed improved ways of enabling preferred resources to participate in its competitive procurement process. SCE intends to draw on this experience in conducting its All-Source RFOs pursuant to its AB 57 BPP authority. Particular lessons from the LCR RFO relevant to the All-Source RFOs include an active outreach to preferred resource suppliers, including serving material on the CPUC's EE and DR service lists as well as the LTPP service list. Additionally, SCE developed *pro forma* contracts, spreadsheets to convey bid attributes, and other documents that specifically accommodate the unique attributes of each of the preferred resources. In addition, SCE clarified within the RFO instructions that the existing *pro forma* contracts are intended to accommodate

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[12] The list of SCE's authorized procurement products is contained in Appendix A to SCE's Proposed 2014 AB 57 BPP in Attachment C. These products are currently listed as "Forward Energy (demand side)," "Capacity (demand side)," and "On-site energy or capacity," respectively in SCE's existing 2010 Conformed AB 57 BPP. The "Capacity (demand side)" product is also currently listed in SCE's authorized non-standard product list. SCE therefore also clarifies in Appendix B, Sheet B-1 to SCE's Proposed 2014 AB 57 BPP that this non-standard product is the Demand Response product.

[13] Attachment C, Appendix A, Sheet A-1.

renewables or distributed generation with interconnection at the distribution grid level. SCE will adapt these approaches, to the extent practical and applicable, to procure preferred resources in its All-Source RFOs for residual bundled procurement. These changes will enhance the opportunity for preferred resources to participate in SCE's All-Source RFOs and contribute to serving SCE's residual need.

The ability to define these preferred resource products within this AB 57 BPP will also enable a direct head-to-head comparison of offers to meet the required need. SCE, however, does not propose any changes to the LCBF methodology that is used to evaluate offers in its bilateral or solicitation processes, as it already appropriately accounts for all value and cost components and will directly consider preferred resources' particular attributes and characteristics.[14] As with conventional resource procurement, it is the evaluation of these costs and benefits along with qualitative criteria such as GHG reductions that will determine if SCE should procure a specific resource. Thus, once products are clearly defined in SCE's list of authorized products, the current methodology will be able to fairly evaluate the particular attributes of the preferred resources.[15]

For example, DR may provide short-term benefits in terms of quick response and low incremental price, but the LCBF methodology can also evaluate the longer-term risk to the availability of the resource if it is called on too often. By recognizing DR as a unique product,

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[14] Attachment B, Section IV.A.5 "Evaluation and Selection of Resources Through an RFO Process," at Sheets 18-23. Within All-Source solicitations, resources capable of providing the needed product (*e.g.*, energy, capacity, operating flexibility, etc.) are solicited with a technology-neutral approach. *See id.* at Sheets 20-21.

[15] Specifically, for each evaluation, SCE fully reflects in its valuation process the value of carbon reduction arising from the procurement of preferred resources. Also, the selection process takes into account "best fit" constraints such as capacity and energy needs, as well as qualitative characteristics such as location, product type, procurement limits, portfolio diversity benefits and "fit" with the State's policy goals, particularly with regard to preferred resources. During the selection process, SCE's tools and process evaluate different combinations of portfolios that meet the required needs. SCE is able to calculate the marginal cost of procuring higher Loading Order resources when they compete in a true All-Source solicitation. This allows for an informed decision regarding procuring a portfolio that better aligns with the State's policy objectives.

bidders can offer bid prices and frequency of use limits that can be systematically valued using the LCBF methodology. As such, SCE's LCBF methodology is robust and capable of valuing the preferred resources as defined in SCE's Proposed 2014 AB 57 BPP.

In order to comply with the Loading Order, when assessing the residual needs that are to be met for a specific procurement activity executed pursuant to SCE's AB 57 BPP, SCE will consider the ability of all resources in meeting these identified needs. This may lead to SCE defining, evaluating, and assessing the benefits of resources differently than is typically done in explicit procurement activities such as procurement to support demand-side management program goals. For example, SCE may value EE bids as the net present value of the project's contribution towards reducing the residual net short energy position each month of the contract term. These savings would be measured as the difference between what would have happened with and without the particular EE contract for the respective procurement period.[16] SCE will present the exact approach that it plans to utilize for each respective procurement activity to its PRG, the Energy Division (ED), and the Independent Evaluator (IE), prior to receipt of final offers. SCE will follow LCBF principles in all procurement activities it performs consistent with Commission rules.

B. Request for Pre-Approval of a New Renewable Product for Transactions Less Than Five Years in Duration to Support the Loading Order

Like other preferred resources already approved in SCE's existing 2010 Conformed AB 57 BPP where SCE seeks clearer product definitions, there are current and real circumstances in which a Renewables Portfolio Standard (RPS)-eligible resource could also successfully compete within a less-than-five-year duration All-Source RFO.[17] For example, SCE has seen in the

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[16] For example, SCE may propose methods for valuing projects that accelerate savings up to code.

[17] SCE identifies that the costs of certain renewable technologies have continued to decline. This decline may ultimately produce a resource with a fully installed cost on a capacity basis that is equal to or even less than gas-fired generation. In addition, the eventual full build out of resources

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market a limited number of occasions in which an RPS-eligible resource has either: 1) recently had a long-term contract expire and has either a) chosen to sell its renewable energy into the market and separately sell its Resource Adequacy attributes or b) not yet obtained a new contract; or 2) newly come online, reached commercial operation prior to the beginning delivery date of its contract, and may be interested in a less-than-five-year contract. During those periods where the resource is capable of producing energy and providing capacity, but is not under contract, the resource owner may seek a short-term contract, especially if it is seeking to capture applicable tax credits.

Although SCE has the authority to procure renewable resources through an All-Source RFO as standard energy and capacity, renewables are not an authorized product in SCE's AB 57 BPP and thus are not eligible for submission through the AB 57 BPP process.[18] Thus, SCE requests authorization to conduct transactions of less than five years in duration through the AB 57 BPP with ERRs that are able to compete head-to-head with other preferred and conventional resources and meet all of SCE's other upfront standards and criteria.

Allowing SCE to procure energy and renewable attributes from such resources within its AB 57 BPP without requiring additional CPUC approval would ensure that SCE's customers are afforded the same opportunity as other load-serving entities to procure resources not only needed to meet an identified need, such as RPS targets, but to also meet *residual* bundled procurement needs in accordance with the continuing Loading Order obligation.[19] Currently, there is disparate treatment of ERR bids based on their technology. Other preferred and conventional resources that are compliant with the upfront standards and criteria in SCE's AB 57 BPP can be

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necessary to meet RPS requirements may produce an excess of renewable capacity, making more resources available for shorter contract duration solicitations.

[18] *See* D.12-01-033, at 52, OP 14 ("Southern California Edison Company's proposal to enter into short-term renewable energy transactions is not approved. . . .").

[19] *See* D.12-01-033, at 51, OP 4. *See also* D.04-12-048, at 80 ("[R]enewable bids are to be favored in the all-source solicitation process to the extent that they provide the desired electricity product and are cost-competitive in light of our greenhouse gas policies.").

submitted through SCE's QCR process without Commission approval.[20] However, it appears that ERRs – even those otherwise meeting all of the upfront standards contained in SCE's AB 57 BPP – would have to be submitted for approval through an application. In D.04-12-048, the Commission stated:

> We should note that the approval process of renewable contracts will differ depending on whether the contract is procured via an all-source or RPS solicitation. As determined in D.04-07-029, renewable contracts from an RPS solicitation will be submitted to the Commission for approval with advice letters. However, renewable contracts from all-source solicitations must be submitted with an application.[21]

The requirement that energy and capacity from ERRs procured through an All-Source solicitation to meet bundled procurement need must be submitted for approval through an application presents a discriminatory burden upon a preferred resource not shouldered by other preferred resources and conventional generation and would appear to be counter to the Loading Order. That is, other preferred and conventional resources are able to submit a bid and have that transaction executed without any further regulatory approvals, while a renewable resource must submit a bid contingent on Commission approval and face delay and market uncertainty during what is often a lengthy contract approval process. This delay and the incremental risk in obtaining pre-approval create additional costs, uncertainty, and disparity between resource bidders, and diminish the ability of SCE to pursue ERRs in its residual procurement processes.

This delay and market uncertainty can have material implications for the competitiveness of ERRs in an All-Source RFO. From the outset, ERRs will be unable to offer contract start dates that are impossible to meet due to the approval process. Moreover, other preferred and conventional resources submitting a bid into an All-Source RFO have certainty that the time

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[20] Although the ED's Director approves SCE's QCR, this approval letter means that the quarter's transactions were compliant with its AB 57 BPP and *per se* eligible for cost recovery in the Energy Resource Recovery Account (ERRA). It is not a reasonableness review process such as an advice letter or application for contract approval.

[21] D.04-12-048, at 108 (emphasis added).

between their bid and contract commencement is not subject to approval delays. However, the lengthy review and the uncertainty from the approval process could eliminate the opportunity for the ERR to be offered to other market participants. This approval risk is then generally included in the resource's offer to account for the price volatility risk associated with their inability to participate in alternative profitable sales. As a result, that price risk included in the bid typically translates into a premium above that of an approved product in SCE's AB 57 BPP, which is not subject to the same review and approval process. This premium is simply reflective of the opportunity risk imbedded within the offer of the renewable resource. SCE seeks to eliminate this disparity and "level the playing field" by allowing ERRs which are competitively selected in an All-Source RFO to be subject to the same streamlined QCR process as other preferred and conventional resources.

This proposal to allow ERRs to equitably participate in the All-Source RFO is different than the current RPS "fast-track" approval process adopted by the Commission in D.09-06-050 or any other RPS "procurement reform" measures currently being considered in the dedicated RPS proceeding in Rulemaking 11-05-005.[22] It does not intend to replace any process in the RPS proceeding governing procurement of ERRs that are compared only to one another solely to meet RPS targets and which may be purchased at a premium compared to other resources. Rather, SCE seeks authority to use the same QCR process for ERRs that are able to compete head-to-head with other preferred and conventional resources in meeting SCE's residual bundled procurement needs by having equal attribution as an authorized AB 57 BPP product. Thus, SCE seeks authority to procure an "Eligible Renewable Resource" product, as described in Appendix

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[22] *See* D.12-01-033, at 52, OP 14 ("Southern California Edison Company's proposal to enter into short-term renewable energy transactions is not approved, but may be addressed in the Renewables Portfolio Standard proceeding, Rulemaking 11-05-005."). Unlike SCE's AB 57 BPP framework, measures in the RPS proceeding do not address SCE's residual bundled procurement activities where all resources can compete on a head-to-head basis consistent with D.12-01-033's direction that there is a continuing Loading Order obligation. Therefore, the LTPP is the appropriate forum for SCE's proposal to add an authorized ERR product in its Proposed 2014 AB 57 BPP.

A of its Proposed 2014 AB 57 BPP[23] *in addition* to the fast-track approval process or any revised process adopted in the RPS proceeding. This is arguably more consistent with the intent of D.04-12-048's guidance that "the all-source solicitations are meant to complement our ongoing work in the RPS program, and to present a second opportunity for renewable resource development to take place"[24] than the existing rules prohibiting SCE from submitting transactions with ERRs through the QCR process. It also provides a clear method for SCE to implement D.12-01-033's direction that there is a continuing Loading Order obligation.

SCE asks that the Commission allow SCE to enter into contracts with ERRs under its AB 57 BPP authority with the same review process as other authorized AB 57 BPP products. That is, the renewable transactions will be subject to all of the same AB 57 rules which, if followed and approved in SCE's QCR, result in transactions that are *per se* eligible for cost recovery with no further application or advice letter approval process.

III.

BUNDLED NEED ANALYSIS SETTING SCE'S RATABLE RATES AND POSITION LIMITS

A. Procurement Limits and Ratable Rates

Except for the differences in resource assumptions explained in this Section, SCE used the same rates and limits methodology for calculating annual electric capacity, energy, gas, and GHG position limits and ratable rate limits as was used in SCE's 2010 Conformed AB 57 BPP. This methodology is detailed in SCE's Proposed 2014 AB 57 BPP in Section IV.C.4 and accompanying Appendix E. The confidential rates and limits tables are also provided in Appendix E.

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[23] Attachment C, Appendix A, at Sheet A-1.
[24] D.04-12-048, at 80-81.

In the 2013 update to SCE's existing rates and limits in Advice 2957-E, dated October 31, 2013 (2013 Update), the gas limits SCE calculated were understated. In Section IV.C.4.d.2 of the 2014 AB 57 BPP, it states that monthly natural gas position limits are the sum of SCE's forecast gas requirements minus delta adjusted hedges in SCE's portfolio for each month assuming a 2-standard deviation high implied market heat rate based on (1) economic dispatch of SCE's existing portfolio; and (2) an equivalent volume of natural gas that would be required to serve SCE's forecast net-short electrical energy position.[25] SCE recently became aware that limits calculated in the 2013 Update did not include item (2), an equivalent volume of natural gas that would be required to serve SCE's forecast net-short electrical energy position. This results in 2014 AB 57 BPP gas position limits that are 39% higher than those calculated in the 2013 Update for the 2015-2016 period. Had SCE correctly calculated the gas limits incorporated in the 2013 Update, the 2014 AB 57 BPP gas position limits would be 0.4% lower for the 2015-2016 period.

B. Planning Assumptions and Approach

SCE developed its ratable rates and position limits in its 2014 AB 57 BPP based on SCE's BPP Analysis described below. SCE's BPP Analysis was conducted in accordance with the Trajectory Scenario,[26] as directed by the Scoping Memo.[27]

In SCE's BPP Analysis, SCE assumed compliance with all mandates and assumptions as directed by the Commission to implement preferred resource programs. As part of SCE's compliance with the Loading Order, the ratable rates and position limits, among other things,

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[25] Attachment B, at Sheet 63.

[26] The Trajectory Scenario was originally outlined in the Assigned Commissioner's Ruling On Assumptions, Scenarios and Renewables Portfolio Standard (RPS) Portfolios For Use in 2014 Long-Term Procurement Plan (LTPP) and 2014-2015 California Independent System Operator (CAISO) Transmission Planning Process (TPP), dated February 27, 2014 (ACR). On May 14, 2014, the Assigned Commissioner issued a ruling containing technical updates to the planning assumptions and scenarios for use in the 2014 LTPP (Updated ACR). SCE's analysis described herein used the Trajectory Scenario outlined in the Updated ACR.

[27] Scoping Memo, at 9.

serve as a restraint on SCE's forward procurement of conventional resources, prevent available conventional resources from "crowding out" preferred resources, and ensure preferred resources have multiple opportunities to enter SCE's portfolio as SCE ratably fills its residual need. At the same time, the ratable rates and position limits also allow SCE to adequately meet any energy and capacity needs in the immediate future.

Table III-1 below summarizes the major assumptions used to perform the BPP Analysis, which relied on the Commission's standardized planning assumptions in the Updated ACR (Updated ACR Assumptions).[28]

[28] The definitions of the Trajectory Scenario, including the load forecast, EE, DR, and demand-side combined heat and power (CHP), can be found in Table 6: Scenario Matrix on page 39 of the Updated ACR.

Table III-1

Key Input Assumptions

Input Assumptions	SCE's 2014 AB 57 BPP Planning Assumptions
Demand Forecast	California Energy Commission's (CEC's) 2013 Integrated Energy Policy Report (IEPR) Demand Forecast "Mid (1 in 2) Demand and Mid AAEE"[29] Case
Load Migration	Migrating load that has occurred up to the end of 2013 due to the partial reopening of Direct Access (DA) set by SB 695
Natural Gas Prices	CEC's 2013 IEPR Natural Gas Reference Case for Henry Hub price; SCE locational burner tip adders
GHG Prices	CEC's 2013 IEPR Natural Gas Market Assessment: Outlook Report
CO_2 Emission Rates	Gas-fired resources based on contract or model heat rate and natural gas emission rate of 117 lbs/MMBtu; Import emission rate as specified in California Air Resources Board (CARB) regulations
Power Prices	Forecasted using PLEXOS security-constrained unit commitment and dispatch production cost simulation of the Western Electricity Coordinating Council (WECC) region
RPS Portfolio	SCE's existing portfolio, plus generic resources to achieve 33% RPS by 2020 using the generic resource composition based on CPUC's 33% 2024 Mid AAEE RPS Portfolio
CHP Portfolio	SCE's existing portfolio recontracts at contract expiration to remain in portfolio until Dec. 31, 2024

The sections below provide additional details about SCE's BPP Analysis based on the Updated ACR Assumptions.

1. Load Forecast (Demand Forecast)

For the BPP analysis, the Commission directed the IOUs to use the Updated ACR Assumptions for the Trajectory Scenario, which set specific values for load forecast, EE, DR,

[29] SCE used the CEC's 2013 IEPR Final Demand Forecast updated in April 2014. AAEE stands for "additional achievable energy efficiency" or uncommitted EE.

and demand-side CHP. The Commission also directed the IOUs to use the CEC's "Managed Load" forecast. SCE used the Mid (1-in-2) Base Demand combined with the Mid AAEE projection from the CEC's Final 2013 IEPR Demand Forecast as the "Managed Load" forecast for its BPP Analysis.

a) CPUC's Trajectory Scenario

SCE adopted the CPUC's Trajectory Scenario load forecast as the basis for its BPP Analysis for two primary reasons. First, the Trajectory Scenario is consistent with the CPUC's Updated ACR Assumptions. Second, SCE's own internal bundled load forecast aligned well with the Trajectory Scenario load forecast for the first five years in the ten-year planning horizon. In addition, pursuant to SCE's existing process of annually updating its ratable rates and position limits through an advice letter filing so long as those updates are consistent with the approved limits methodology, SCE can reflect any update to the CEC's load forecast that may be necessary.[30]

b) Direct Access (DA) Assumptions

D.14-02-040 requires SCE to plan for a reasonable amount of departing load in its AB 57 BPP.[31] The closure of the DA partial reopening at the end of 2013 has reduced uncertainty regarding DA migrating load estimation. Because SCE used the CPUC's Trajectory Scenario as the basis for its BPP Analysis, SCE verified that the CEC's Mid Base Demand Forecast reflected all of the DA migrating load since the end of 2013.[32] The CEC reflected a reasonable level of

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[30] For example, if the use of the CEC's load forecast is part of the approved methodology to set SCE's rates and limits in this 2014 LTPP, SCE would provide its yearly update of its rates and limits in the interim year using the CEC's most updated forecast, such as the CEC's interim demand forecast update, if available.

[31] D.14-02-040, at 74-75, OP 1.

[32] Pursuant to D.04-12-048, the anticipated Lancaster Community Choice Aggregator (CCA) was not included because a binding notice of intent has yet to be filed and thus cannot be included in this LTPP forecast.

DA migrating load in the forecast period. Therefore, SCE's use of the CEC's bundled load forecast in the Trajectory Scenario satisfies the Commission's requirement to reflect a reasonable amount of DA departing load for its bundled procurement targets.

c) Hourly Bundled Energy Forecast

The CEC's Trajectory Scenario load forecast only provided the annual energy and peak forecasts for the ten-year planning period of 2015 to 2024. Thus, SCE converted the CEC's annual bundled sales forecast, which is measured at the meter level, to a forecast of bundled customer energy at the CAISO.[33] In addition, SCE had to convert the CEC's 1-in-2 annual SCE retail peak forecast, which was measured at the generation level, to a forecast of annual bundled peak load at the CAISO.[34]

Next, SCE had to derive the hourly load forecast by allocating the CEC's annual energy forecast to the hourly level and at the same time match the peak hour load forecast with the CEC's annual peak demand forecast. SCE developed a simple method for this purpose by applying SCE's own 8,760 hourly load shape to the CEC's annual energy forecast and then adjusting the hourly load forecast to match the CEC's annual peak forecast. As a result, the hourly load forecast reflected the CEC's annual energy and peak demand forecasts and SCE's hourly load shapes.

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[33] The CAISO settles SCE's bundled load. Bundled customer sales and bundled customer energy are measured at different grid interfaces. Bundled sales represent the energy delivered to and measured at the customer meter as it is billed. Bundled energy at the CAISO represents the energy delivered to the customer meter plus distribution losses measured during the hour it is consumed. SCE used a distribution loss factor of 4.8% consistent with what SCE assumed in its previous 2010 BPP Analysis.

[34] SCE first converted the CEC's 1-in-2 annual SCE retail peak forecast at the generation level to a forecast of annual retail peak at the CAISO level by accounting for transmission losses. SCE used a transmission loss factor of 2% consistent with what SCE assumed in its previous 2010 BPP Analysis. Then, SCE applied the annual growth rates based on the CEC's retail peak forecast at the CAISO to SCE's recorded 2013 bundled peak load at the CAISO to derive its ten-year forecast of the bundled peak load at the CAISO.

2. Demand-Side Resources

a) AAEE Assumptions

Energy efficiency forecasts were developed from the CEC's 2013 IEPR Mid Base Demand forecast and its supplemental AAEE projections. The AAEE forecast reflects the incremental uncommitted EE beyond the committed EE, which is already captured in the CEC's Mid Base Demand Forecast. As directed by the Updated ACR Assumptions in the Trajectory Scenario, SCE utilized the AAEE Mid Case, which was developed from the CPUC's 2013 Energy Efficiency Potential Goals Study.[35] Table III-2 below reflects the AAEE forecast specified in the Trajectory Scenario.

Table III-2

Total AAEE Savings for SCE Service Territory

Mid AAEE Forecast	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Energy (GWh, Includes Losses)	1511	2694	3815	4723	5643	6470	7357	8255	9238	10239
Peak (MW, Includes Losses)	259	514	749	972	1187	1382	1593	1813	2058	2308

b) DR Assumptions

In its 2013 IEPR forecast, the CEC incorporated DR programs, including non-event-based programs such as time-of-use pricing and permanent load shifting and event-based programs such as Critical Peak Pricing (CPP) and Peak Time Rebate (PTR), in its peak demand forecast as a demand reducer.[36] The estimate of the total additional DR impact on SCE's planning area peak demand forecast is reflected in Table III-3 below.

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35 Updated ACR, at 10-12.

36 *See* CEC 2013 IEPR Forecast, updated Apr. 2014, at 37 and 38 *at* http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-V1-CMF.pdf.

Table III-3

Total DR Impact for SCE's Planning Area

DR Impact in MW	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Event-Based DR	25	25	25	25	25	25	25	25	25	25
Non-Event-Based DR	12	12	12	12	12	12	11	11	11	11
Total DR	37	37	37	37	37	37	36	36	36	36

c) Self-Generated/Distributed Generation (SG/DG) Assumptions

Table III-4 below reflects the behind-the-meter DG or self-generation assumed in the CEC's 2013 IEPR Mid Base Demand Forecast for SCE's planning area.

Table III-4

Total DG or Self-Generation for SCE's Planning Area

DG/Self-Gen Forecast	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Total DG in GWh	6734	6910	7007	7116	7232	7368	7549	7758	7996	8263
Total DG in MW	1184	1220	1241	1265	1290	1321	1363	1412	1468	1532

3. Supply-Side Resources

SCE modeled its assumptions concerning renewables, CHP, supply-side DR, and energy storage resources in accordance with the Updated ACR Assumptions. Where ACR Assumptions were ambiguous, further clarification was sought from the ED. These clarifications were applied to SCE's BPP Analysis and are detailed below.[37]

a) Renewable Generation Portfolio Assumptions

Per the Updated ACR Assumptions and Scenarios[38] and the Scoping Memo, SCE used the "regular" version of the RPS Calculator tool (RPS Calculator)[39] with the Mid Case AAEE assumptions and Mid Load (1-in-2) forecast to populate SCE's expected RPS portfolio.

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37 Conference call with the ED on June 17, 2014.
38 Updated ACR, at 35.

In a departure from the assumption in SCE's 2010 Conformed AB 57 BPP, SCE's 2014 AB 57 BPP assumed that ERRs with expiring contracts would not be recontracted. Instead, SCE assumed that the energy from these resources would be replaced by a generic RPS portfolio containing the same technology composition as the statewide generic RPS portfolio forecasted by the RPS Calculator. This change reflects the fact that since 2010, most expiring RPS contracts in SCE's portfolio either have chosen not to recontract with SCE, or were unable to offer competitive bids during SCE's solicitations of ERRs. The departure from SCE's 100% recontracting assumptions in its 2010 AB 57 BPP reflects SCE's experience and allows SCE to assume a future RPS portfolio consistent with recent experience in establishing bundled procurement needs.

Beyond replacement of expiring RPS contracts, SCE also added generic RPS resources to cover shortfalls in meeting its procurement quantity requirements[40] to achieve the 33% RPS goal by 2020 and maintain this percentage of RPS energy contribution annually thereafter. Additional generic RPS resources used for this purpose were also assumed to consist of a portfolio with the same technology mix as the statewide generic RPS portfolio forecasted by the RPS Calculator.

As a conservative measure, SCE assumed surplus RPS energy forecasted from its existing RPS portfolio in Compliance Period 1 and 2 will meet unexpected annual variations in RPS production. In the BPP Analysis, SCE did not use this energy as a bank to reduce the amount of preferred RPS resources that must be procured to meet procurement quantity requirements.

Continued from the previous page

39 The RPS Calculator is a publicly available spreadsheet model for forecasting the level of renewables in California under various scenarios. The consulting company, Environmental and Energy Economics (E3), developed the model under contract to the CPUC. A copy of the RPS Calculator can be downloaded from the CPUC website at: http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/2012+LTPP+Tools+and+Spreadsheets.htm.

40 *See generally* D.11-12-020, at 8, n.12 (citing Pub. Util. Code § 399.15(b)(4)).

b) Conventional Supply Portfolio

SCE's conventional supply portfolio for the BPP Analysis consists of its utility-owned generation (UOG) and existing contracts. SCE's UOG is detailed in Section III.C.1 of the 2014 AB 57 BPP.[41] In addition to its UOG, SCE has existing contracts with other gas-fired resources. These contracts include tolling contracts with full RA capacity and dispatch rights, energy-only tolls, and RA capacity tags.

4. GHG, Natural Gas, and Power Price Forecasts

a) GHG and Natural Gas Price Forecast

SCE used the Mid Case GHG and natural gas price forecasts from the 2013 IEPR Natural Gas Market Assessment: Outlook Report,[42] as the base for forecasting fundamental energy market prices used to calculate expected commitment and dispatch of its dispatchable resources, as well as forecasting SCE's GHG exposure/requirements for SCE's BPP Analysis. These prices were the baseline assumption used by the CEC in forecasting demand in the IEPR. Therefore, the GHG and natural gas prices are congruent with demand.

b) Energy Price Forecast

SCE used GHG and natural gas prices described above as inputs into the PLEXOS security-constrained economic commitment and dispatch model to forecast fundamental power prices in SCE's service territory. The industry standard PLEXOS model took into account the fuel distribution and transmission topology, the operating characteristics of existing and potential power plants, the capacities of existing and planned transmission lines in the WECC, and SCE's internal forecast of energy demands of different load centers across the WECC in dispatching

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41 Attachment B, at Sheet 8.

42 CEC-200-2013-006: Appendix E-3, CEC Natural Gas Assessment Report 2013. The Excel table containing numerical data was provided separately by the Commission on July 3, 2014.

generation resources at least cost to meet the regional load forecast. The marginal cost of generation in SCE's service area set the base case hourly fundamental market clearing price forecast. SCE then used observed market volatility of the implied market heat rate (IMHR) to create two-standard deviation high and low energy market price scenario forecasts. The IMHR is defined as the SP-15 power price divided by SoCal border natural gas cost since January 1, 2013. This is the date that California implemented its AB 32 cap-and-trade program, which has impacted SP-15 power prices. Therefore, price relationships prior to that program's implementation would be different than in today's market.

C. Planning Analysis

SCE performed the BPP Analysis based on the assumptions discussed above. SCE conducted the following analyses concerning SCE's need, utilizing consistent methodologies:

1. Capacity Need
2. Energy Need
3. Natural Gas Need
4. GHG Physical and Financial Exposure

The details of the planning analysis activities are described below.

1. Capacity Need Determination

As required by the Scoping Memo, SCE determined its capacity need based on the difference between the forecast bundled customer load plus 17% reserve margin, and the estimated total RA capacity of SCE's existing supply portfolio, including DR.

2. Energy Need Determination (Residual Net Long/Short Forecast)

SCE forecasted its energy position by performing economic unit commitment and dispatch analysis of SCE's projected portfolio using the PROSYM security-constrained unit commitment and dispatch simulation engine, taking the forecasted power, GHG, and natural gas

prices as input. SCE calculated the net short or long position on an hourly basis by subtracting the total economic energy production of its UOG and contract portfolio from the demand forecast, and aggregating them into gross monthly on- and off-peak MWh values.

3. Natural Gas Need

SCE forecasted its natural gas needs by performing economic unit commitment and dispatch analysis of SCE's projected portfolio using the PROSYM security-constrained unit commitment and dispatch simulation engine, taking the forecasted power, GHG, and natural gas prices as input. SCE calculated the total natural gas need by adding two separate components: 1) Gas required to support the forecasted unit commitment and dispatch of its UOG and contract portfolio, and 2) Gas equivalent of energy market purchases required to cover net energy short position on a hourly basis based on the forecasted power, GHG, and natural gas prices. The gas needs are aggregated into monthly values.

4. GHG Direct Compliance and Financial Exposure Forecast

The CARB adopted a set of regulations pursuant to AB 32's goal of reducing GHG emissions to 1990 levels by 2020. SCE based its estimates of GHG emissions on the accounting rules of D.12-04-046.[43]

For the BPP Analysis, SCE forecasted the total portfolio GHG direct compliance obligation and financial exposure to GHG allowance prices as a proxy for the overall GHG emissions of the portfolio. Under the AB 32 cap-and-trade program, SCE's bundled customers are responsible for all GHG emissions created in generating the power they consume. This is the case as SCE must either procure and retire GHG allowances to meet its direct compliance obligation, or pay the cost of contracted power, which can reasonably be assumed to include the

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[43] D.12-04-046, Appendix 1.

cost of GHG allowances within the contract. SCE therefore forecasts the total GHG direct compliance obligation and financial exposure incurred to serve its bundled customers' load.

SCE forecasts its total GHG direct compliance obligation by using the contractual or operating heat rate and fuel GHG emission rate to determine the total tonnage of GHG emissions associated with the forecasted commitment and dispatch of SCE's generating and tolling resources. SCE also included its direct compliance obligation arising from being the "First Jurisdictional Deliverer"[44] of any out-of-state energy import.

SCE forecasts two separate GHG components to arrive at the total GHG financial exposure resulting from the impact of AB 32's cap-and-trade regime on the financial payments it makes to various counterparties. The first component is the impact of AB 32 on SCE's contractual payments to its Qualifying Facility (QF) and non-QF renewable resources. The second component is the impact of AB 32 on the prices of the electrical energy SCE expects to procure from the California electricity market (*e.g.*, SP-15 or NP-15) in order to meet the energy demands of its bundled customers.

IV.

SCE'S ADDITIONAL CHANGES TO ITS PREVIOUSLY AUTHORIZED AB 57 BUNDLED PROCUREMENT PLAN

A. Modifications to the Customer Risk Tolerance Rate

In 2012, D.12-01-033 adopted a new methodology for calculating the CRT rate, which is used to calculate the CRT. The CRT is used as part of the overall hedging framework to instruct IOUs as to when portfolio risk has reached certain levels that the Commission requires PRG

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[44] The CARB has defined this term and for any entity deemed to be a First Jurisdictional Deliverer of imported energy, there is a reporting and compliance obligation for the emissions associated with the imported power.

consultation and to keep the IOU's PRG informed on potential market outcomes.[45] The 2012 decision adopted a new indexing mechanism for the CRT rate versus the historical fixed rate mechanism that had been in place since 2002. The new CRT rate was set at 10% of each utility's system average rate to be updated every two years using the then-current system average rate.[46] At the time, SCE had also recommended that the CRT be reviewed in its biennial LTPP filings.

By setting a new CRT rate, the Commission provided a higher threshold metric that dictates when consultation with the IOU's PRG must be conducted to consider how the IOU should proceed with its hedging program.[47] Hedging to reduce such risk can and does occur below that threshold. This however leads to the inevitable question of how far below that threshold should hedging occur. In order to provide better clarity on this, SCE seeks to better align the CRT such that PRG consultations do not happen only during extreme market cases. As explained below, lowering the CRT would mean proposals for incremental hedging can be discussed with SCE's PRG and acted upon before the customer portfolio has the potential to experience a $1.2 billion dollar event over the next 12 months. At that current consultation threshold, hedging may no longer be useful because the only options would be to hedge into the rising environment or hope that the market returns to normal.

SCE's few years of experience with the new CRT rate and resulting CRT have shown that some adjustments to this guiding metric are necessary so that PRG consultation can occur at a more appropriate threshold. Since adoption in 2012, the new CRT rate and resulting CRT combined with the 95th percentile Time to Expiration Value at Risk (TEVaR) metric, if used as a

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45 D.12-01-033, at 25 ("If the CRT is expected to be hit or exceeded within the next quarter, the PRG is to be notified and additional remedial action is to be considered, consistent with the process described in D.07-12-052.").

46 *Id.* at 51, OP 5.

47 *See id.* at 24 (". . . [The] CRT figure represented the rate level at which a PRG meeting would be required and remedial action would be considered, such as additional hedges."). *See also id.* at 25 ("If the CRT is expected to be hit or exceeded within the next quarter, the PRG is to be notified and additional remedial action is to be considered, consistent with the process described in D.07-12-052.").

guiding target before proceeding with hedging, would have led to no incremental hedging for SCE from a TEVaR management perspective. Although the direction from the Commission was that the new CRT rate would reduce both the amount and the cost of hedging,[48] it has primarily resulted in no incremental hedging need for TEVaR management when used by SCE as a target. In fact, the current CRT rate when combined with recent market conditions (*i.e.*, as of the end of August 2014) results in an outcome that would indicate no hedging for TEVaR management is needed, even if SCE were to procure 100% of its load from the market. In other words, the CRT is now set so high that even with a portfolio fully exposed to market prices, no hedging would be necessary to stay below that metric. As a result, SCE's customers could be exposed to additional and higher procurement costs of about $1.2 billion above forecast – essentially a 40% increase in procurement expenses before a consultation with SCE's PRG would be required under the CRT. This represents a substantial risk to customers and should be reevaluated. Recent increases in natural gas prices due to this winter's unseasonably cold temperatures put upward pressure on costs and rates that cause SCE to question the magnitude of what customers would tolerate as an acceptable risk and potential cost exposure.

The CRT is an important data point within SCE's hedging framework and is used to determine when consultation is required with its PRG. Having a CRT set so high that consultation is never required with the PRG diminishes the value of having a CRT at all. Two critical components of the CRT rate derivation were adopted in D.12-01-033: (1) the underlying index used to set the CRT rate and (2) the percentage level to apply to the index. SCE proposes to update the underlying index used to set the CRT rate. In 2012, it was determined that indexing the CRT rate to the utility's system average rate was more logical than a fixed flat rate that never changed. SCE does not strongly oppose an indexed approach, but questions the use of the system average rate as the appropriate index.

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[48] *Id.* at 26.

The hedging framework is designed to hedge customers' exposure against significant market price increases and their impacts on procurement cost. The system average rate, however, is comprised of more than just market procurement costs (*e.g.*, base rates and certain balancing accounts). As these non-market costs increase, so does the CRT rate. This creates a perverse outcome where a customer's tolerance to increases in market procurement costs becomes artificially inflated as a result of other non-market cost increases.

For example, assume the system average rate is 10 cents/kWh and 50% (5 cents/kWh) of the rate is due to market procurement costs and the other 50% (5 cents/kWh) is due to other costs. The CRT rate would be set at 1 cent/kWh (10% of 10 cents/kWh). Then assume that two years later the system average rate has increased to 12 cents/kWh, but the increase is all from non-market related costs (*i.e.*, the total rate is comprised of 5 cents/kWh (42%) of market procurement costs and 7 cents/kWh (58%) from non-market costs). The CRT rate would now be 1.2 cents/kWh (10% of 12 cents/kWh). The customer's tolerance for market movements and their impact on procurement cost have just increased even though nothing has happened in the market or the total market cost of serving the customer. Arguably, the customer tolerance should have at least remained unchanged.

Given that the CRT plays an important role in the hedging framework and that the objective of the hedging framework is to mitigate against potential significant rate increases,[49] a more logical underlying index for setting the CRT rate would be the ERRA portion of the system average rate as it pertains to energy procurement costs.

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[49] *See id.* at 23 ("[The CRT] is used as a metric to guide the utilities in determining their appropriate level of hedging against potential electric rate increases.").

The second component of the CRT rate is the percentage that should be applied to the underlying index. SCE proposes to maintain the current 10% rate as SCE is not aware of any substantive studies on collective customer risk tolerance.[50]

In summary, SCE proposes in its AB 57 BPP[51] that the CRT be derived as follows so that the threshold for the required PRG consultation is more meaningful:

1. A base load forecast scenario in kWh for the applicable rolling forward 12-month period is prepared.
2. The total 12-month load forecast is multiplied by the then-current CRT rate, which is expressed in cents/kWh. This represents the CRT that is compared to the prompt 12-month TEVaR calculation.
3. The CRT rate will be 10% of the ERRA portion of SCE's system average rate.

B. RA Sales as a Non-Standard Product

SCE requests approval to add RA Sales to the list of authorized non-standard products. The 2012 LTPP Track 3 decision directed the IOUs to treat RA capacity as a standard product and to reflect this in their BPPs.[52] The rationale for this directive was that the IOUs could procure RA capacity through competitive processes. Typically, there are limited buyers for SCE's surplus RA capacity and a robust market is unlikely to become available for sales in the foreseeable future. In addition, these buyers typically look to procure their RA requirements right before the RA compliance deadline when they have greater certainty regarding their RA requirements. This makes either an expedited RA sale RFO or a filing for approval of specific sales impractical. The re-classification of RA to a standard product has impacted the ability of SCE to supply excess RA to other market participants and thereby realize value for customers for

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50 SCE also notes that a CRT based on total bundled customer energy procurement requirements does not impact customers equally. Specifically, SCE's tiered retail rate structure disproportionately exposes higher tier usage customers to energy market risk.

51 Attachment C, Appendix J, at Sheet J-5.

52 D.14-02-040, at 41.

any surplus RA it may hold. As a reference, SCE sales of RA have reduced overall customer costs by approximately $6-8 million per year.

By designating an RA Sales product as non-standard, SCE can sell this product bilaterally, subject to adequate price support in the QCR, for terms longer than one quarter and/or with delivery beginning longer than one quarter forward (*i.e.*, Medium-Term transactions).[53] Enabling SCE to sell RA into the market would not only benefit SCE's customers, but assist external parties in meeting their RA requirements to ensure the reliability of the State's electric grid.

An RA Sales product meets the existing definition of a non-standard product because the complexity and unique nature of each transaction make them unlikely to be offered through a broker or exchange.[54] SCE is not aware of any broker or exchange currently offering this product. SCE's proposed RA Sales product has been added to the non-standard product list in Appendix B of SCE's Proposed 2014 AB 57 BPP.

C. Brokered Transactions for All GHG Products

SCE proposes that it be allowed to use brokers for transactions of approved GHG compliance products (GHG Products). This would be consistent with methods that have been approved previously by the Commission for use with other energy products, and would give SCE access to an additional volume of GHG compliance instruments for the benefit of its customers.

In its initial decision regarding GHG procurement rules, the Commission noted that the record at the time did not support a liquid and transparent market for allowances and offsets, and, for that reason, the Commission restricted the mechanisms through which the IOUs would be allowed to transact these products.[55] Now, based on nearly three years of trade data, a majority

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[53] Attachment B, at Sheet 54.

[54] *See id.* ("'Non-standard products' are products that satisfy a particular operational or procurement requirement but are not liquidly traded through exchanges or brokers.").

[55] D.12-04-046.

of traded volume for California cap-and-trade GHG products has been brokered. In fact, 81% of California Carbon Allowance (CCA) futures have been over-the-counter (OTC)-cleared transactions (also known as "block trades") that were transacted through brokers since the futures contract went live in August 2011, and 85% of CCA futures have been block trades since the California cap-and-trade program's compliance period began on January 1, 2013.

With regard to GHG offset credits, more than 10 million metric tons of CARB compliance offsets have traded through the brokered market. This compares favorably to the total volume of eligible offset credits that was offered into SCE's GHG offset credit RFO in early 2014.

SCE therefore proposes to use OTC electronic and voice brokers to purchase and sell GHG Products to hedge its customers' GHG exposure. OTC electronic and voice brokers allow SCE to simultaneously reach multiple potential counterparties with visible and representative pricing. Visible and representative pricing means any interested market participant can see the price, and the posted price and quantity will determine the final transaction costs. Brokers match buyers and sellers of standardized products without revealing the participants' identities. Once an agreement on price is made, the broker will reveal the buyer's and seller's identities to each other, but not to the market, so that the two parties can complete the transaction. SCE uses similar, Commission-approved, reputable OTC brokers to purchase and sell other energy-related products to hedge its customers' exposure (*e.g.*, natural gas and energy).[56]

For GHG offset credit products, using brokers will reduce the administrative burden and costs involved with running a competitive solicitation, which, currently, is the only transactional mechanism available to SCE for GHG offset credit procurement. The brokered market would also allow SCE to maximize the benefits of offset procurement for its customers, by transacting in a manner that better matches its procurement/compliance needs.

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[56] See Attachment B, at Sheet 50 for a description of SCE's existing authority to use brokers. Appendix D lists SCE's authorized brokers.

Additionally, having access to the brokered markets allows SCE to conduct larger volume transactions than what is available on approved exchanges. Currently, the typical size of a screen-traded exchange transaction is 5,000 or 10,000 metric tons. The size of block trades is typically an order of magnitude greater. Given the limited liquidity in the secondary market, transacting directly over the exchange in small volumes could result in price movements; whereas, working through brokers for larger volumes could mitigate that risk. Ultimately, this flexibility would result in reduced GHG procurement costs for SCE's customers.

SCE seeks Commission authorization to use any of the brokers on the list of Authorized Brokers and Exchanges in Appendix D for procurement of approved GHG Products. This proposed change is reflected in SCE's Proposed 2014 AB 57 BPP in Section IV.C.2.b at Sheet 47, which adds brokers as an authorized transactional process for GHG Products.

D. Modifications to the "Linkage Rule" for Medium-Term Transactions

SCE proposes to modify the "linkage rule" that the Commission clarified in D.14-02-040 in the last LTPP cycle for the purpose of determining the term of a "Medium-Term" transaction.[57] SCE's proposal discussed below is designed to avoid unintended consequences that may result from this linkage rule that seem to conflict with the Commission's other directives and policy goals.

The current linkage rule provided in D.14-02-040 states that, for the purpose of Medium-Term and Long-Term contracts, multiple contracts entered into around the same time, for the same resource, and for consecutive time periods are considered one contract and may not be treated as different transactions for Commission approval. For the purpose of determining the "term" of a contract, two or more contracts, for consecutive time periods including contractual options are treated as one (linked), where:

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[57] See Attachment B, at Sheet 29, n.40 for the definition of Short-Term, Medium-Term, and Long-Term transactions.

a. They specify the same resources as the primary delivery source or, for an unspecified source, they are with the same counterparty; and
b. They are negotiated or executed within any three consecutive-month period, except if entered into as a result of separate RFOs and the contract from the earlier RFO is executed before the later RFO has received any bids (either indicative or final).[58]

This rule poses challenges and uncertainties within the compliance framework of the AB 57 BPP. In particular, it may conflict with the LCBF upfront standard by precluding SCE from accepting "least-cost" offers for Short-Term transactions if such offers came from the same counterparty over consecutive months since it would trigger a linkage. Further, unintentional linkage of Short-Term transactions could preclude SCE's efforts to procure from diverse suppliers and/or products ("best fit") that have demonstrable value to its customers.

SCE provides the following example of the negative ramifications of the linkage rule in its current form on the LCBF principle:

> Example of Short-Term "Lowest Offer": SCE negotiates and executes a power transaction for a standard product with a counterparty on July 7th for a term beginning September 1st through 30th (Short-Term) from an unspecified source. The transaction is for firm On-Peak Power. On August 10th, SCE receives an offer from the same counterparty for a term October 1st through December 31st (Short-Term) from an unspecified source.

Though both offers were the best available at their respective times, they are effectively "linked" because the two deals had consecutive delivery terms and a) were with the same counterparty from an unspecified source and b) were executed within a three consecutive-month period. The linkage rule would effectively make these two Short-Term transactions linked as a single Medium-Term transaction. Thus, SCE could not execute the second deal because SCE does not have authority to execute Medium-Term bilateral transactions for a

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[58] D.14-02-040, at 40.

standard product.[59] The linkage rule would force SCE to execute the second procurement transaction with a different counterparty at a higher price, resulting in higher costs to SCE's customers.

SCE understands the Commission's concern that multiple contracts could be executed which individually are compliant with Commission rules, but when viewed as a combined transaction are not compliant. However, SCE's example above does not appear to violate the Commission's concern of an IOU avoiding procurement rules around Medium-Term bilateral transactions through multiple contracts. In that example, SCE and the counterparty did not design the transaction to occur one after the other. Instead, the circumstances of the market resulted in the same counterparty offering the least-cost product for Short-Term deliveries that happened to be consecutive.

Given the tradeoff between LCBF alternatives and preventing the potential for combined deals in excess of Commission authorization, SCE believes that the best approach is to instead apply the linkage rule to those transactions which are of greater consequence, and which may be the focus of the Commission's concern. With that objective in mind, SCE recommends that the Commission amend D.14-02-040's linkage rule for the purpose of Medium-Term transactions to apply to tolling agreements only. This proposal is consistent with the above objectives in that tolling agreements are typically for entire resources, which suggests that they are for large quantities of energy.

SCE believes limiting linkage requirements for Medium-Term transactions to tolling contracts is the most practical application of D.14-02-040's linkage rule that balances the need to ensure compliance with the Commission's rules, including LCBF principles. This proposed limitation is reflected in SCE's Proposed 2014 AB 57 BPP at Sheet 52, footnote 55.

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[59] *See* Attachment B, at Sheet 52 ("SCE is authorized to use direct bilateral contracts for Short-Term Transactions.").

E. Streamlined Procedures for AB 57 BPP Updates/Conformed Filings

1. Updates to GHG Limits Submitted Via Tier 1 Advice Letter Consistent With Updates To SCE's Energy, Capacity, and Natural Gas Limits

SCE proposes a more streamlined approach for its updates to all AB 57 BPP rates and limits through the existing advice letter process. Currently, SCE provides an update to its electricity and natural gas position limits and ratable rates in the form of a Tier 1 advice letter during years in which SCE does not file an updated conformed AB 57 BPP.[60] In addition, and in accordance with D.12-04-046, SCE is required to file an update to its GHG transaction rates and procurement limits in the form of a separate Tier 2 advice letter.[61] Both advice letters are submitted on or before October 31st. This existing process provides SCE with the opportunity to adjust its position limits and transaction rate limits to reflect changes in SCE's portfolio and updated forecast assumptions.

Since SCE's last approved AB 57 BPP in the 2010 LTPP cycle, the GHG cap-and trade market has operated in a consistent manner. In the course of the last three years, the GHG cap-and-trade market has had over 10 auctions and numerous sales transactions. The market has demonstrated stability and is no longer in its infancy. The GHG cap-and-trade market now resembles a well-established commodity market and thus maintaining a limit update consistent with other energy products would be a prudent improvement to the GHG limit process, as well as present an opportunity to simplify and streamline the filing process.

As such, SCE proposes that all updates to SCE's procurement limits and ratable rates, including its GHG transaction rate and limits, be filed through a single Tier 1 advice letter filing during years in which SCE does not file an updated, conformed AB 57 BPP, or more often if necessary. This change is reflected in SCE's Proposed 2014 AB 57 BPP at Sheets 68-69 and 78.

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[60] Advice 2713-E-B (SCE's 2010 Conformed AB 57 BPP), dated July 23, 2012, at Sheet73.
[61] *Id.*

SCE will maintain the same schedule by submitting the annual single advice letter by October 31st with an effective date of January 1st of the year following the submittal, unless suspended or otherwise instructed by the Commission. SCE will also calculate the updated position limits and transaction rate limits using SCE's Commission-authorized limits methodology.

2. Conformed Filings Submitted Via Tier 2 Advice Letter

SCE also recommends that the Commission adopt a Tier 2 advice letter process for approval of the IOUs' conformed AB 57 BPPs. Although there is no standard requirement as to the tier designation for IOUs to submit their conformed AB 57 BPP filing, the Commission ordered the IOUs in the 2010 LTPP to submit the conformed filings through a Tier 3 advice letter. The conformed filing is a compliance obligation and is designed to allow the Commission to evaluate whether the changes made by the IOU are in conformance with Commission orders. Therefore, there is no reason to require another full Commission decision via resolution for a conformed filing once the Commission's decision in the LTPP proceeding has approved the proposed AB 57 BPPs. This unnecessarily delays the approval process. It also creates uncertainty as to which requirements are effective during the interim between the final decision approving the AB 57 BPPs and a final resolution approving the conformed AB 57 BPPs.

Since the Commission decision in the LTPP approves the IOUs' proposed AB 57 BPPs with modifications, the IOUs are simply carrying out any Commission's changes within the Ordering Paragraphs to their plans through their conformed filings. As such, Commission General Order 96-B, Industry Rule 5.2(2), describing matters appropriate to a Tier 2 advice letter, is the most relevant to the conformed AB 57 BPP filings:

> **5.2 Matters Appropriate to Tier 2 (Effective After Staff Approval)**
>
> Matters appropriate to Tier 2 are:
>
> (2) A tariff change that is consistent with authority the Commission previously has granted to the Utility submitting the

advice letter, such as a rate change within a price floor and ceiling previously approved by the Commission for that Utility.

If the IOU did not carry out those changes properly, then the ED should prepare the filing for a Commission resolution. But if all changes do conform to the decision, then Staff approval is appropriate because it is merely a "ministerial act" ensuring compliance with the Commission's orders. This proposed change is reflected in SCE's Proposed 2014 AB 57 BPP at Sheet 78.

V.

CONCLUSION

For all the foregoing reasons, the Commission should approve SCE's Proposed 2014 AB 57 BPP and Appendices, including the modifications discussed herein.

Respectfully submitted,

WILLIAM V. WALSH
AMBER WYATT
MELISSA HOVSEPIAN

/s/ Melissa Hovsepian
By: Melissa Hovsepian

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

2244 Walnut Grove Avenue
Post Office Box 800
Rosemead, California 91770
Telephone: (626) 302-6054
Facsimile: (626) 302-6962
E-mail: Melissa.Hovsepian@sce.com

October 3, 2014

Attachment A

Summary of Changes in SCE's Proposed 2014 AB 57 BPP

Summary of Changes in SCE's Proposed 2014 AB 57 BPP

From SCE's Conformed 2010 AB 57 BPP

Table A-I. Description of Modifications in SCE's Proposed 2014 Plan (Attachment B)

2014 BPP Section	Modifications
I. Overview	• Updated to reflect 2014 LTPP cycle and Scoping Memo • Section I.A. "Changes Since Previous Procurement Plan" moved to Appendix K • I.B. "Decisions Pending or Recently Issued Related to Procurement" moved to Appendix K
II. SCE's Planning and Procurement Approach Pursuant to the Loading Order	• Moved description of how SCE adheres to the Loading Order to this separate section. Description was previously in Section III. "Input Assumptions and Need Determination For the AB 57 BPP." • Reflects the clarification of three previously approved products – EE, DR, and DG – and the addition of Eligible Renewable Resources to the list of authorized procurement products
III. Input Assumptions and Need Determination for the AB 57 BPP	• Substantial modifications to entire section to reflect SCE's BPP Analysis based on the CPUC's Trajectory Scenario in the 2014 LTPP
IV. A.1. and 2. Procurement Process	• Minor clean up changes
IV.A 3. Price Forecasting Methodology for Support of Procurement Planning and Operations	• Substantial modifications to reflect SCE's BPP Analysis based on the CPUC's Trajectory Scenario in the 2014 LTPP
IV.A.4. through 7.	• Minor clean up changes
IV.B.1. through 3.	• Minor clean up changes
IV.B.4. Customer Risk Tolerance	• Amends the derivation of the CRT rate by applying the fixed percentage risk tolerance factor to the ERRA portion of SCE's system average rate • Clarifies that the CRT update will occur two years from the approval of SCE's conformed BPP filing
IV.B.5. Credit and Collateral Requirements	• Minor clean up changes and clarifications • Slight revision to provide clarity on the benefits of a secured lien holder
IV.C.1. Contract Duration	• Minor clean up changes and clarifications
IV.C.2 Authorized Electric, Natural Gas, and Emissions Procurement Products	• Reflects the clarification of three previously approved products – EE, DR, and DG – and the addition of Eligible Renewable Resources to the list of authorized procurement products • Modified to reflect authority to transact GHG Products through brokers • Incorporates relevant portions of previous Appendix I describing SCE's GHG procurement authority
IV.C.4. Procurement Limits and Ratable Rates	• Minor clean up changes and updates • Incorporates relevant portions of previous Appendix I

	describing SCE's GHG transaction rate limits • Combines SCE's updates to all ratable rates and limits, including GHG, in one Tier 1 Advice Letter
V. SCE's Resource Acquisition Strategy	• Substantial modifications to entire section to update SCE's ongoing efforts and reflect SCE's proposed clarifications and additional product in furtherance of the Loading Order
VII.E.2. Updates or Modifications to AB 57 BPP	• Specifies that the conformed AB 57 BPP pursuant to an LTPP decision will be filed via Tier 2 Advice Letter, updates to all position and ratable rate limits in years that SCE does not file an updated conformed BPP will be submitted via Tier 1 Advice Letter, and the CRT update will occur two years from the approval of SCE's conformed BPP filing

Table A-II. Description of Modifications in SCE's Proposed 2014 Appendices (Attachment C)

2014 BPP Appendix	Modifications
Appendix A - Authorized Procurement Products for Energy and Energy-Related Products	• Updated the definition of Energy Efficiency, Demand Response, and Distributed Generation replacing prior products listed as Forward Energy (demand side), Capacity (demand side), and On site energy or capacity, respectively • Added Eligible Renewable Resources as an authorized procurement product • Deleted Back to Back Tolls, Day Ahead Unit Contingent Call Options, and Residual Back to Back Tolls as each product was associated with the energy auction process pursuant to new generation procurement on behalf of all benefitting customers, which is now defunct pursuant to D.14-02-040
Appendix B – Authorized Non-Standard Products	• Edited Demand Response for consistency with authorized product definition • Added RA sales only
Appendix D – Authorized Brokers and Exchanges	• Added CGS Brokerage LLC and Trident Brokerage Services LLC pursuant to Advice Letter 3104-E
Appendix E – Procurement Limits and Ratable Rates Tables	• Updated all tables and moved GHG limits tables from previous Appendix I to this appendix
Appendix J – Valuation and Risk Management Considerations	• Modified CRT rate by applying the fixed percentage risk tolerance factor to the ERRA portion of SCE's system average rate
Appendix K – Changes Since Previous Procurement Plan and Decisions Pending or Recently Issued Related to Procurement	• Updated to reflect Advice Letter updates and relevant procurement decisions since SCE's 2010 Conformed AB 57 BPP
Appendix L – Organizational Structure of SCE's Power Procurement Business Unit	• Revised to reflect recent organizational structure changes

2010 BPP Appendix	Modifications
Previous Appendix F – Demand Forecast and Demand-Side Resource	• Removed and captured in detail throughout Plan under Section III.B
Previous Appendix I – Greenhouse Gas	• Removed as a stand-alone appendix and captured in Plan and Appendices
Previous Appendix K – Planning Assumptions	• Moved and captured in Plan under Section III.B
Previous Appendix L – Roadmap of Changes From the 2006 Conformed LTPP	• Replaced by this Attachment
Appendix Q – Glossary of Terms	• Removed as a stand-alone appendix due to its voluminous content and incorporated throughout Plan and Appendices

Table A-III. List of Re-Ordered Appendices in Attachment C

Appendix	Title	Previous Appendix
A	Authorized Procurement Products for Energy and Energy-Related Products	C
B	Authorized Non-Standard Products	O
C	Authorized Transactional Processes for Energy and Energy-Related Products	D
D	Authorized Brokers and Exchanges	E
E	Procurement Limits and Ratable Rates Tables	J and I
F	Unsecured Credit Limits	M
G	Congestion Revenue Rights	G
H	Convergence Bidding	H
I	Contract Limitations with Power Generation Facilities Utilizing Once-Through Cooling	P
J	Valuation and Risk Management Considerations	N
K	Changes Since Previous Procurement Plan	A
L	Organizational Structure of SCE's Power Procurement Division	B

Attachment B

SCE's Proposed 2014 AB 57 Bundled Procurement Plan

Southern California Edison

Rosemead, California (U 338-E)

SOUTHERN CALIFORNIA EDISON COMPANY'S
PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN

SOUTHERN CALIFORNIA EDISON COMPANY'S
PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN

ATTACHMENT B

CLEAN VERSION

(To be inserted by utility)		Issued by	(To be inserted by Cal. PUC)	
Advice		Megan Scott-Kakures	Date Filed	
Decision		Vice President	Effective	
1D0			Resolution	

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PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN
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I.

OVERVIEW

Southern California Edison Company (SCE) hereby submits this 2014 Conformed Assembly Bill (AB) 57 Bundled Procurement Plan (BPP or Plan), pursuant to Decision (D.) XX-XX-XXX. SCE originally submitted this AB 57 BPP to the California Public Utilities Commission (CPUC or Commission) on October 3, 2014, in accordance with the Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge (ALJ), dated May 6, 2014 (Scoping Memo) in Rulemaking (R.) 13-12-010. In accordance with AB 57,[1] the Scoping Memo stated that "by approving procurement plans, the Commission establishes 'up-front standards' for the [investor-owned utilities' (IOUs')] procurement activities and cost recovery."[2] SCE's 2014 Conformed AB 57 BPP covers years 2015 through 2024. The Commission reviewed and approved the AB 57 BPP, with certain changes as specified in D. XX-XX-XXX, in Phase 2 of the 2014 Long-Term Procurement Plan (LTPP) proceeding. By approving SCE's AB 57 BPP, the ratable rates and position limits, products, transactional processes, and other rules described in this Plan represent the upfront standards and criteria that establish SCE's pre-approved authority to procure to meet its bundled customers' needs.[3] If SCE's transactions are executed in compliance with these approved standards and criteria, its procurement-related expenses are *per se* eligible for cost recovery. The scope of SCE's pre-approved AB 57 authority is limited to transactions with a

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1 Stats. 2002, ch. 850, Sec 3, effective September 24, 2002, which added Pub. Util. Code § 454.5, enabling utilities to resume procurement of electric resources.

2 Scoping Memo, p.9, n.4.

3 The Commission has defined "'bundled' as pertaining to an IOU's load and resources in its role as a Load Serving Entity (LSE)." R.10-05-006, Order Instituting Rulemaking (OIR), issued Dec. 3, 2010, n.5. SCE's AB 57 BPP describes the ratable rates and limits and the products and procurement processes approved by the Commission to meet SCE's bundled customer needs. By contrast, "system" planning usually relates to the need for new resources in each IOU's service area and that benefit all LSEs in the service area. *See id.* at n.4.

(Continued)

duration of less than five years.[4] As directed by the Scoping Memo,[5] this AB 57 BPP is based on the Trajectory Scenario which was defined in the attachment to the Assigned Commissioner's Ruling On Assumptions, Scenarios and Renewables Portfolio Standard (RPS) Portfolios For Use In 2014 Long-Term Procurement Plan (LTPP) and 2014-2015 California Independent System Operator (CAISO) Transmission Planning Process (TPP), dated Feb. 27, 2014 (ACR).[6]

This 2014 Conformed AB 57 BPP replaces SCE's 2010 Conformed AB 57 BPP, which was filed on July 23, 2012 via Advice 2713-E-B. This AB 57 BPP incorporates a tariff-like numbering system as ordered by the Commission in D.07-12-052.[7] In accordance with the Commission's previous decisions, SCE will make any proposed updates or modifications to the 2014 Conformed AB 57 BPP before the next biennial procurement plan proceeding through an Advice Letter process.[8] SCE will include redlined pages of the 2010 Conformed AB 57 BPP, as well as clean replacement pages, in the Advice Letters for any such proposed revisions.

II.

SCE'S PLANNING AND PROCUREMENT APPROACH PURSUANT TOTHE LOADING ORDER

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4 D.12-01-033, p.47, Finding of Fact (FOF) 24.

5 Scoping Memo, p.9 ". . . [The Commission] direct[s] the IOUs' filing of bundled LTPPs to be based on the Trajectory Scenario of the Assumptions, Scenarios and Renewable Portfolio Standard Portfolios adopted in the [*sic*] for use in the 2014 Long-Term Procurement Plan by the February 27, 2014 ruling.").

6 The planning assumptions and scenarios contained in the ACR were updated by the Assigned Commissioner Ruling issued on May 14, 2014. *See* Assigned Commissioner's Ruling Technical Updates to Planning Assumptions and Scenarios for Use in the 2014 Long Term Procurement Plan and 2014-15 CAISO TPP (May 14, 2014) (Updated ACR).

7 *See* D.07-12-052, Ordering Paragraphs (OP) 25 and 26.

8 *Id.* at OP 26.

(Continued)

This AB 57 BPP presents an integrated plan that follows the State's Energy Action Plan (EAP) II and Loading Order. SCE takes several actions to ensure its planning and procurement decisions are consistent with the EAP II. SCE's adherence to the Loading Order is an on-going obligation. This AB 57 BPP clarifies three previously approved products – Energy Efficiency (demand side), Demand Response (demand side), and Distributed Generation (demand side and supply side) – and adds Eligible Renewable Resources (ERR) as a new product.

SCE's 2014 Conformed AB 57 BPP adheres to the State's EAP II and Loading Order through both SCE's planning and procurement activities. In SCE's bundled need analysis establishing its ratable rates and limits, SCE assessed the current status of both the SCE portfolio and the broader system of which that portfolio is a component. Then, SCE accounted for any known or projected changes in future loads and resources. Next, SCE used this data to identify the bundled need, subject to established procurement criteria such as Resource Adequacy (RA). Finally, SCE added resources in Loading Order priority to meet applicable statutory and regulatory requirements using a mix of resources and products that are likely to be viable and least cost to SCE's customers and a best fit for the bundled portfolio. The Loading Order priority is:

1. Energy Efficiency (EE) and Demand Response (DR)
2. Renewable Sources
3. Distributed Generation (DG)
4. Clean and Efficient Fossil-Fueled Generation

In SCE's residual procurement activities, SCE takes four specific actions to align its procurement decisions with the EAP II and Loading Order.

First, prior to every competitive procurement that allows fossil-fueled resources to participate, SCE updates its procurement needs by refreshing the latest forecasts for Demand-Side Management (DSM) programs, current renewable procurement, and any efficient combined heat and power (CHP) procurement. SCE uses Clean and Efficient Fossil-Fueled Generation resources only for "residual" procurement when higher-priority, cost-effective resources are unavailable.

(Continued)

Second, SCE layers in its procurement over time, *i.e.*, "ratably." This ensures that currently available fossil-fueled resources do not "crowd out" upcoming preferred resources in meeting needs several years ahead. Section IV.C.4 and Appendix E provide the procurement limits and ratable rates for such procurement.

Third, SCE commonly uses all-source solicitation formats in its AB 57 procurement,[9] which allows all preferred resources to compete rather than limiting procurement to fossil-fueled technologies. Thus, preferred resources beyond those procured through SCE's EE, DR, and Renewables Portfolio Standard (RPS) programs have the opportunity to compete economically with fossil-fueled resources.

Finally, SCE includes in its production cost forecast the cost of complying with the AB 32 cap-and-trade regime. This allows the full economic advantages of zero greenhouse gas (GHG) emissions to be properly accounted for in the competitive solicitation to fill SCE's residual procurement need.

III.
INPUT ASSUMPTIONS AND NEED DETERMINATION FOR THE AB 57 BPP

The BPP Analysis identified SCE's available resources and procurement authority required to meet its bundled customers' capacity and energy demand over the planning horizon. SCE's 2014 Conformed AB 57 BPP covers the period 2015 through 2024 to allow for a rolling 10-year procurement authority effective Calendar Year 2015. SCE's procurement limits include a margin to cover market variations in addition to the base forecasted bundled need to ensure that the procurement authority would remain adequate to serve bundled customers and RA requirements within a reasonable range of market conditions.

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9 SCE has other more focused competitive solicitations limited to renewable, CHP, and solar photovoltaic (PV) resources that it takes into account in its planning efforts.

A. SCE's AB 57 BPP Conforms to the CPUC's Trajectory Scenario

SCE's 2014 Conformed AB 57 BPP utilized the Trajectory Scenario specified in the Scoping Memo, RA requirements, and natural gas price forecasts. Although SCE's 2014 Conformed AB 57 BPP conformed to inputs and assumptions specified in the Trajectory Scenario, SCE also made conservative assumptions for parameters that the Commission did not explicitly specify.

Table III-1 below shows a summary of SCE's BPP Planning Assumptions.

(Continued)

Table III-1
Input Assumptions of SCE's BPP Analysis

Input Assumptions	SCE's 2014 AB 57 BPP Planning Assumptions
Demand Forecast	California Energy Commission's (CEC's) 2013 Integrated Energy Policy Report (IEPR) Demand Forecast "Mid (1 in 2) Demand and Mid AAEE"[10] Case
Load Migration	Migrating load that has occurred up to the end of 2013 due to the partial reopening of Direct Access (DA) set by SB 695
Natural Gas Prices	CEC's 2013 IEPR Natural Gas Reference Case for Henry Hub price, SCE locational burner tip adders
GHG Prices	CEC's 2013 IEPR Natural Gas Market Assessment: Outlook report
CO_2 Emission Rates	Gas-fired resources based on contract or model heat rate and natural gas emission rate of 117 lbs/MMBtu. Import emission rate as specified in California Air Resources Board (CARB) regulations
Power Prices	Forecasted using PLEXOS security constrained unit commitment and dispatch production cost simulation of the Western Electricity Coordinating Council (WECC) region
RPS Portfolio	SCE's existing portfolio, plus generic resources to achieve 33% RPS by 2020 using the generic resource composition based on CPUC's 33% 2024 Mid AAEE RPS Portfolio
CHP Portfolio	SCE's existing portfolio recontracts at contract expiration to remain in portfolio until Dec. 31, 2024

The following sections provide details of SCE's planning approach.

10 SCE used the CEC's 2013 IEPR Final Demand Forecast updated in April 2014. AAEE stands for "additional achievable energy efficiency" or uncommitted EE.

(Continued)

B. Load Forecast (Demand Forecast)

Consistent with the Updated ACR[11] Assumptions, SCE established its "Managed Load" forecast for its BPP Analysis based on the Trajectory Scenario, or Mid Base Demand combined with the Mid AAEE projection from the CEC's Final 2013 IEPR Demand Forecast.[12] Consistent with D.14-02-040, SCE verified that the CEC's Mid Base Demand forecast captures all the Direct Access (DA) migrating load, which has occurred up to the end of 2013 due to DA partial reopening set by Senate Bill (SB) 695. Correspondingly, the CEC's bundled load forecast excluded the estimated DA departing load. SCE converted the CEC's annual bundled sales forecast, which is measured at the meter level, to a forecast of bundled customer energy at the CAISO. In addition, SCE converted the CEC's 1-in-2 annual SCE retail peak forecast, which is measured at the generation level, to a forecast of annual bundled peak load at the CAISO.

SCE derived its hourly bundled load forecast by applying its internal hourly load shape with minimum adjustment to ensure that its energy and peak forecasts matched exactly with the CEC's annual forecasts at the annual level. The CEC's "Mid Base Demand plus Mid AAEE" forecast incorporated assumptions for demand-side resources including EE, DR, and behind-the-meter DG resources.

C. Supply-Side Forecast of Committed Resources

SCE's supply-side resources are used to meet demand that has been adjusted for demand-side resources described above. SCE provides below a description of its supply-side portfolio. SCE addresses its procurement strategy for supply-side resources in Section V.

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11 The definitions of the Trajectory Scenario, including the load forecast, can be found in Table 6: Scenario Matrix on page 39 of the Updated ACR.

12 The CEC released its revised final 2013 IEPR Demand Forecast in April, 2014. The forecast details can be found at the CEC's website, http://www.energy.ca.gov/2013_energypolicy/documents/demand-forecast_CMF/LSE_and_Balancing_Authority_Forecasts/.

(Continued)

1. Utility-Owned Generation (UOG)

SCE owns and operates: 33 hydroelectric plants; two combined cycle gas turbines (CCGTs) – MountainView Unit Nos. 3 and 4; and five combustion turbine (CT) peaker units – Barre, Center, Grapeland, McGrath, and Mira Loma. SCE also owns a 15.8% interest in Palo Verde Nuclear Generating Station Unit Nos. 1, 2 and 3, located in Maricopa, Arizona, which is operated by Arizona Public Service (APS). SCE also owns and operates 91 megawatts (MW) of solar facilities located on commercial rooftops or ground-mounted. These facilities are all assumed to be available during the period covered by SCE's 2014 Conformed AB 57 BPP.

2. Available Demand Response

In addition to physical generating resources, SCE also operates 11 Dispatchable Demand Reduction (DDR) programs that fall under Emergency, Price Responsive, Aggregator Managed and SmartConnect program types. DDR can be used to offset forecasted Bundled Demand, and reduce additional procurement needs in a manner similar to UOG.

3. Recontracting of Renewable Resources

SCE's 2014 Conformed AB 57 BPP assumed expiring renewable resource contracts will not recontract. This is based on SCE's experience that most expiring RPS contracts did not choose to recontract with SCE, contracted with other LSEs, chose to sell into existing markets, or could not bid competitively against other available RPS resources during SCE's open RPS solicitation.

4. Recontracting of CHP Qualifying Facility (QF) Resources

All CHP QF contracts expiring between 2015-2024 are assumed to recontract until the end of 2024.

D. Bundled Need Determination

SCE's 2014 Conformed AB 57 BPP forecast SCE's load and available supplies to determine the residual procurement required to meet the projected needs of SCE's bundled customers. In developing SCE's 2014 Conformed AB 57 BPP, SCE made the following

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assumptions concerning system limitations that could impact its ability to procure the resources required to serve its bundled customers.

- Transmission
    a. In-State – SCE assumed that there is adequate transmission capacity in the CAISO to deliver available renewable and conventional energy to meet SCE's energy needs.
    b. Out-of-State – SCE assumed it will continue to have import capacity proportional to its approximately 40% load-ratio share.[13] SCE will acquire the necessary transmission products (*e.g.*, CRRs, transmission rights, etc.) to ensure the cost-effective delivery of out-of-state energy resources.
- Reliability – SCE assumed the reliability products required by the CPUC and the CAISO to ensure reliability of the grid would be available in the market for SCE to procure.
- CAISO Markets – SCE assumed that it will have continued access to CAISO Ancillary Services (AS) markets through which it can purchase needed and sell surplus AS products.

1. Bundled Portfolio: Categories of Resources

SCE satisfied a substantial portion of its future portfolio needs with preferred resources from the Loading Order. However, after taking into consideration known EE, DR, renewable procurement, DG programs, efficient CHP, utility-owned resources and existing contractual arrangements, there remained a residual net short (RNS) position in future years, although a

[13] The load-ratio share is the methodology the CAISO uses to allocate import capacity rights to LSEs based on their proportionate share of the forecast coincident peak load for the CAISO Control Area.

residual net long (RNL) position may occur in some periods within each year. SCE anticipated its RNS would be filled through procurement of approved products as defined in this AB 57 BPP. SCE will procure the approved products using approved procurement mechanisms, including brokers, exchanges, Requests for Offers (RFOs), bilateral transactions, or via cleared markets such as CAISO markets.

SCE assessed its bundled portfolio need based on three categories of resources:

1. Existing resource commitments. These resources included existing EE, DR, renewables contracts, DG programs, QF and CHP contracts, executed and Commission-approved renewables contracts, SCE-owned generation, existing bilateral and inter-utility agreements, and resources procured through prior RFOs.
2. Generic planned resources to meet Loading Order resource targets or other planning criteria, such as RA capacity. These resources included planned EE and DR resources, and renewable resources to meet a 33% renewable energy goal.
3. Transactions required to fill the RNS after taking into account (1) and (2) above. SCE will obtain these resources via market purchases through RFOs, bilateral deals, or from the traded or CAISO markets using SCE's authorized products, transaction processes, and procurement limits.

Section V below details how SCE will acquire the resources filling the need identified in this Section.

(Continued)

2. Supply- and Demand-Side Forecast for Existing or Planned Resources

In determining total procurement need, SCE focused on SCE's existing and known resource commitments. SCE grouped loads and supply- and demand-side resources in accordance with the Scoping Memo.[14]

SCE took into account committed supply-side resources in developing its procurement authority limits, as Section III explains in further detail. Committed supply-side resources included UOG, existing contracts, executed and Commission-approved renewables contracts, and existing programs. SCE accounted for anticipated future growth or decay in their capabilities and efficiencies. SCE also incorporated anticipated generic resources needed to meet State policy goals, such as a 33% renewable energy goal and the California Solar Initiative (CSI).[15] SCE did not include uncommitted or planned supply-side resources that have not been funded or contracted, and current RFOs that have not yet concluded in determining its procurement authority needs.

3. Capacity Need Determination

SCE forecast its annual capacity need using the largest difference between meter level hourly peak load of its bundled demand plus 17% reserve margin, and the total available Net Qualifying Capacity (NQC) of its forecasted portfolio. Where they are available, SCE used the NQC specified by the Commission for its UOG and Tolling resources[16] in forecasting the total available NQC of its forecasted portfolio. For contracted resources for which NQCs are not specified, SCE used the monthly technology factors provided by the CAISO for estimating NQCs.[17] For generic RPS resources used to achieve the 33% RPS by 2020, SCE also used

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14 Updated ACR, p.8.

15 SCE accounted for all projects approved as of August 10, 2014.

16 Final 2014 NQC List Tab of Commission's scenario tool. Downloaded on June 1 2014, *available at* http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/ltpp_history.htm.

17 *Available at* http://www.caiso.com/Documents/FinalNetQualifyingCapacityList-2014.xls.

(Continued)

monthly technology factors for estimating NQC times name plate capacities of the generic resources. For DR programs, SCE reduced the program MW totals using the CEC's DA forecast.

4. Energy Need Determination (Residual Net Long/Short Forecast)

SCE forecast energy needs and surpluses using economic commitment and dispatch simulation of SCE's bundled portfolio by using SCE's fundamental power price forecast, the 2013 IEPR gas forecast, and GHG price forecasts directed by the Commission. SCE then subtracted the total forecasted energy production from the total forecasted bundled demand for each hour to determine the hourly RNS or Residual Net Long (RNL) position. Due to the discretionary dispatchable nature of portions of SCE's portfolio, SCE's total energy production is sensitive to Implied Market Heat Rates (IMHR) established by electricity market prices, gas prices, and GHG prices. If IMHRs are high, SCE's portfolio would generate more energy, because its dispatchable resources would be more able to provide energy at less cost than the SP-15 energy market. As a result, SCE could experience a RNL energy position during some hours. Conversely, if IMHRs are low, SCE's portfolio would generate less, because the SP-15 energy market would be able to provide energy at less cost than SCE's dispatchable resources. As a result, SCE would see a greater RNS energy position. SCE assumes that a liquid SP-15 market will exist for the duration of the AB 57 BPP for SCE to cover its forecast RNS or sell its forecast RNL.

IV.
PROCUREMENT IMPLEMENTATION PLAN

A. Procurement Process

This Section of the AB 57 BPP discusses SCE's procurement process, risk management strategy, and procurement rules developed for procurement based on the bundled need determination.

SCE's Power Procurement business area ensures that SCE's customers have enough electricity to meet their needs through the output of SCE-owned generation plants and the purchase

(Continued)

of fuel and electricity from wholesale energy markets. Appendix L provides more detailed information on the structure of the Power Procurement organization.

1. SCE's Open-Position Procurement Framework

After accounting for EE, DR, Renewables, DG, CHP, UOG and existing contracts, SCE's customers remain exposed to a variety of financial (price) and physical (delivery) risks associated with unhedged or open positions in RA capacity, electrical energy, ancillary services, transmission, natural gas, natural gas transportation, and emissions products. SCE has a framework for managing these positions based on three basic principles. First, SCE's transactions reduce and/or close open positions, and are not entered into for speculative purposes. Second, SCE generally reduces open positions ratably. This means that SCE reduces or closes portions of the open positions regularly over time in increments rather than sporadically in large pieces. Third, SCE seeks to maximize competition and minimize customer cost in implementing the framework.

In general, the framework for managing SCE's open position begins with a forecast of the open position under a variety of different scenarios, as well as meeting any specific procurement requirements. For example, the Commission's RA requirement dictates all LSEs procure sufficient resources to serve 90% of 115% of their projected peak load hour for each month on a year-ahead basis, and procure sufficient resources to serve 100% of 115% of their projected peak load hour for each month on a month-ahead basis. SCE develops the timing and amount to procure considering a number of different tradeoffs,[18] and ultimately determines such timing and amounts based on an adopted risk tolerance level. SCE then seeks to reduce or hedge its various open positions over time using available markets (*e.g.*, several years forward, prompt year, prompt quarter, prompt month, balance of month, day-ahead, hour-ahead, and real-time) with due deference to any alternative scenarios, using the products (*e.g.*, RA tags, tolls, financial products, transmission

[18] See Hedging Strategy Process diagram in Section IV.B. "Risk Management."

(Continued)

rights), and procurement methods (*e.g.*, RFOs, CAISO auctions, traded transactions), within the limits and rules set forth in its approved AB 57 BPP. The Commission deems *per se* reasonable and pre-approves all transactions executed in accordance with these standards. SCE's established practice is to present and discuss specific hedging strategies, as well as hedging results, with its Procurement Review Group (PRG) and seek its PRG's feedback. SCE also shares with its PRG "Lesson's Learned" after the plans have been implemented.

2. Procurement Process Impact on Resource Dispatch

When SCE procures dispatchable resources in advance of the operating day, decisions regarding the commitment or dispatch of such resources are not determined until near the operating day for three reasons. First, under the CAISO Market Redesign and Technology Upgrade (MRTU) Integrated Forward Market (IFM) structure, the CAISO ultimately determines the mix of dispatchable resources that are committed. The IFM is a daily energy and capacity market, in which hourly energy and ancillary services capacity are "co-optimized" using price and quantity bids submitted by the market participants. Second, as the operating day approaches, knowledge of which resources are available or restricted becomes more accurate. Finally, the spot prices of power and natural gas are not known until one or two days in advance of the operating day. Thus, developing dispatchable resource bids or making resource commitment decisions well in advance of the operating day would not be optimal.

(Continued)

3. Price Forecasting Methodology for Support of Procurement Planning and Operations

a) GHG Price Forecasting

SCE used the mid-case GHG price forecast as put forward in the 2013 IEPR Natural Gas Market Assessment: Outlook Report,[19] as the basis for calculating GHG hedging needs for SCE's BPP Analysis. SCE also used emission rates as specified in the CARB proposed regulations.[20]

b) Gas Price Forecasting

As directed by the Commission in the Updated ACR Assumptions, SCE utilized the CEC's Natural Gas Reference Case[21] as put forward in the 2013 IEPR for calculating natural gas prices. This price series was constructed to be consistent in baseline assumptions with the CEC demand forecast and therefore the two are congruent for planning purposes.

SCE derived gas price volatility using a stochastic process developed by a third party. SCE plans to continue to develop enhancements to its current distribution-based gas price forecasting methods, and to assess and implement other methods as appropriate. SCE expects all of its gas price forecasting tools to evolve and improve over time, with input from SCE's PRG and the ED.

c) Electric Price Forecasting

SCE used the PLEXOS security-constrained economic commitment and dispatch model to forecast fundamental power prices in the SCE service territory, taking into account the fuel distribution and transmission topology, the operating characteristics of existing and potential power plants, and the capacities of existing and planned transmission lines in the WECC interconnection, based on the GHG and natural gas prices forecast as described above. The industry standard

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19 Communicated via e-mail with the Energy Division (ED), dated July 18, 2014.

20 http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-power/acs-power.htm.

21 Communicated via e-mail with the ED, dated July 2, 2014.

(Continued)

PLEXOS model dispatches generation resources at least cost to meet the regional load forecast taking into account operating and transmission constraints. The marginal cost of generation sets the base case hourly fundamental market clearing price forecast. SCE then used observed market volatility of the IMHR, defined as the price of SP-15 power divided by the sum of fuel and GHG emissions cost of energy prices since implementation of the AB 32 cap-and-trade regime, to create two standard deviation high and low market price scenario forecasts.

SCE also derived power price volatility for the purpose of calculating customer procurement cost risk.[22] SCE analytically calculated power price volatility based on gas price volatility and the correlation between power and gas prices.

SCE plans to continue to develop enhancements to its current distribution-based power price forecasting methods, as well as to assess and implement other methods as appropriate. SCE expects all of its power price forecasting tools to evolve and improve over time, and will use new and improved methods with input from its PRG and the ED.

4. Implementation of the Independent Evaluator Requirement

D.08-11-008 requires use of an Independent Evaluator (IE) for all competitive RFOs that seek products lasting two years or more or if there is an affiliate participating in the RFO.[23] SCE, in conjunction with its PRG, develops a pre-qualified pool of at least three IEs. SCE, in conjunction with its PRG and the ED, develops and periodically adds[24] to its IE pool as follows:

1. SCE develops a list of prospective IEs via industry contacts, literature searches, PRG recommendations, and similar methods.

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22 SCE may apply alternative methodologies for developing price forecasts and volatility estimates for other purposes, such as for All-Source RFO contract evaluation.

23 D.07-12-052, OP 9, as modified by D.08-11-008, OP 2. Public versions of IE reports shall be identical to the corresponding confidential versions, except for the visible redaction of confidential material. D.12-04-046, OP 15.

24 SCE will expand its IE pool as needed to maintain a minimum of three IEs and/or to add additional IEs as SCE finds suitable candidates.

(Continued)

SCE then solicits information from the prospective IEs and circulates the list of candidates and their "resumes" to its PRG and ED staff for feedback;[25]

2. SCE relies on the guidance regarding IE expertise and qualifications provided in D.04-12-048. However, SCE recognizes that these qualifications represent the minimum necessary for an IE to be effective, and SCE and its PRG can include additional relevant information that has been gained through experiences implementing the IE requirements;

3. SCE and its PRG then interview a subset of prospective candidates that SCE, its PRG, and ED staff deem most suitable for the role (SCE arranges for its PRG to conduct interviews with candidate IEs in isolation from SCE if desired);

4. SCE requests that its PRG coordinate the development and submittal to SCE of its recommendations on each prospective candidate (including the general consensus and any opposition to the consensus). SCE then prepares and submits a written list of proposed IEs to the ED to add to SCE's pool. The list in part captures the recommendations of SCE's PRG that were submitted to SCE. SCE requests that the ED evaluate the proposed IE's competencies based on the guidelines in D.04-12-048 as well as evaluating the IE's independence including any conflicts of interest. The Commission has given the ED the authority to grant final approval for inclusion of an IE in the IE pool by letter to SCE;[26]

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25 Candidate names will be kept confidential as part of the PRG process.

26 Once the IE pool is established, SCE will select an IE from that pool of candidates after notifying its PRG and the ED of the selected candidate. SCE will submit the preferred IE name to its PRG and the ED no less than 15 days before the IE begins work on the RFO contract. The ED will have final approval of the use of the selected IE for each RFO.

(Continued)

5. Beyond the development of its initial IE pool, additional IEs may be added to SCE's pool by following the same procedures listed above;[27]

6. An IE may remain in the IE pool for three years, pursuant to D.07-12-052 and as further updated by D.14-02-040, after which he/she must go through a re-evaluation process based upon the inclusion criteria to assure continued compliance. The re-evaluation process will involve additional reviews of the IE candidate by SCE's PRG, SCE, and ED staff including additional interviews, if necessary;[28] and

7. SCE developed a *pro forma* contract to be used each time it contracts with an IE and used it to form two separate IE pools to date. SCE plans to continue using that *pro forma* contract, and is not submitting a new *pro forma* IE contract with the AB 57 BPP.

SCE consults with the ED during the development of the scope of work and the drafting of the terms of the contracts. The ED has the right to grant final approval of such engagements. The ED also has the ability to grant final approval of IE *pro forma* contracts at the discretion of the Commission. As noted above, SCE will submit a list of qualified candidates to the ED (including its PRG's feedback); however, the ED will make the final approval of an IE for inclusion in the IE pool.[29] SCE recovers IE costs, as part of the procurement process, through its Energy Resources Recovery Account (ERRA).

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27 If SCE wishes to remove an IE from the pool, it will communicate this to its PRG and to the ED.

28 Review of an IE does not preclude the IE from continuing to remain in the IE pool.

29 IEs are not restricted from participating in two different IOUs' RFOs within the same six-month period.

(Continued)

5. Evaluation and Selection of Resources Through an RFO Process

SCE procures many different types of products through RFO processes.[30] Each product poses unique challenges when it comes to valuation and selection. SCE presents the exact approach utilized for each RFO to the IE, its PRG, and the ED prior to receipt of final offers. SCE follows "Least Cost-Best Fit" (LCBF) principles in all procurement activities it performs per Commission rules.

Generally, RFO evaluations involve two major steps: (1) the valuation of each offer; and (2) the selection of offers. The valuation of each offer takes into account cash flow components for both cost and revenue. These components are then netted and discounted to yield a Net Present Value (NPV) for each offer. The NPV is the factor which is compared to other proposals or options to find the "Least Cost."

"Best Fit" is achieved by ensuring that selected offers fill or manage a procurement need or risk. SCE presents the objective of each RFO to its PRG prior to launch. SCE identifies the exact metrics used to determine best fit prior to receipt of final offers and presents this information to its PRG.

For example, in order to determine the best offers to select for SCE's All-Source RFO, SCE sets up, in advance of final offers, an optimization process that will maximize the NPV of the selected offers. Simultaneously, this process takes into account "best fit" constraints such as capacity, RPS and energy needs, as well as qualitative characteristics such as location, product type, procurement limits, and other "fit" criteria. During the selection optimization, SCE's tools evaluate combinations of offers (without regard to the underlying generation technology) in SCE's All-Source RFO (*i.e.*, offer 1 with offer 2, offer 1 with 2 and 3, and so on for thousands of offers concurrently) to find the mathematically optimal outcome for LCBF. SCE's Gas RFO process also

[30] Appendix A contains a complete product list.

(Continued)

complies with the Commission's LCBF criteria. For each Gas RFO, SCE identifies the most suitable financial and/or physical natural gas hedging instruments to mitigate price exposure risk and/or secure natural gas supply for its portfolio. When SCE identifies the products that fit the natural gas need of its portfolio, through a competitive solicitation (RFO), it will procure LCBF products.

Upon completion of the evaluation stage of an RFO, SCE provides its PRG a decision rationale for its proposed selections and seeks its PRG's feedback before contracts are executed.[31]

a) Valuation Process

For valuation, SCE employs an NPV analysis to evaluate each offer. This NPV analysis estimates:

1. The value of contract benefits;
2. Contract costs; and
3. The net value of 1 and 2.

SCE uses market indicators, such as power, GHG, and gas prices and volatilities, when available, to ensure that valuations are consistent with established markets. However, complete market assessments are not always feasible because of insufficient publication of market indicators. Accordingly, SCE's valuation processes use derived inputs in NPV calculations when market information is not available. These derived inputs come from pricing models and processes which may be fundamental, statistical, or a combination of both. Pricing models and processes may use proxy markets, historical information, proxy physical characteristics, or other information. SCE also considers market information from publicly available sources, such as NYMEX, Platt's, and broker quotes. For example, value components may include, but are not limited to: (1) Energy Benefits defined as the difference between forecasted spot prices and costs; (2) GHG reductions

[31] D.07-12-052, p.149.

(Continued)

defined as the amount of GHG savings not already accounted for in the valuation; (3) Risk Reductions defined as the amount of Time to Expiration Value at Risk (TEVaR) reduction obtained from each offer.

SCE next assesses the present value of the costs of each offer. Costs may include, but are not limited to: (1) fixed monthly capacity/premium payments offered by the seller; (2) transmission upgrade costs, if applicable; and (3) cost adders. Costs incurred related to a contract, but not included in the offer, are handled using cost adders. Different types of cost adders include, but are not limited to: (1) Debt Equivalence; (2) Collateral Cost; (3) GHG Cost; and (4) Credit Risk Cost. Appendix J describes some of these cost adders in more detail. SCE presents the final set of cost adders to be considered for each RFO to its PRG prior to receipt of final offers.

Lastly, SCE subtracts the present value of expected costs from the present value of expected benefits to determine the expected NPV of each offer. The NPV calculation follows the same protocol for all offers.

b) Major Constraints on Bidders

Major constraints placed upon bidders in SCE's RFOs include qualifying criteria and contractual requirements. Qualifying criteria vary depending on the particular RFO, but typically include requirements to make certain representations, warranties, and covenants to SCE, including an agreement to be bound by the conditions of the RFO. RFOs may also include specialized requirements related to the particular products, such as: (1) requirements to comply with the Public Utility Regulatory Policies Act of 1978 (PURPA); (2) maintaining status as a certified CAISO Participating Generator; and/or (3) requirements to meet local, state and federal rules, regulations, standards, permitting requirements, interconnection requirements, and certifications.

Contractual requirements are based on *pro forma* contracts typically included in SCE's RFO documents. SCE does not require that counterparties sign its contracts without modification, but rather attempts to address counterparties' concerns and requirements in a reasonable manner.

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c) "All-Source" Versus "Targeted" RFOs

The Commission has not "ordered" the IOUs to hold All-Source RFOs. Rather, the Commission has found that customers and offerors benefit from allowing the IOUs to have the flexibility to tailor their RFOs, for example, to manage portfolio risk or address system reliability needs such as RA requirements.[32] SCE targets products based upon the current need of its portfolio, other identified needs, or as directed by regulatory mandate. Although each All-Source RFO may vary, SCE intends to solicit some or all of the following products: demand side, such as energy efficiency and demand response, renewable energy, distributed generation tolling agreements, heat rate call options, RA tags, QF agreements and firm energy imports.

d) RFO Scheduling

Within the RFO process, SCE establishes a schedule of events. This schedule includes a date by which contracts pursuant to the RFO shall be awarded.[33] Any contract awarded prior to this date with a counterparty that participated in the RFO is considered awarded pursuant to a competitive RFO. Any contract awarded after that date, whether the counterparty participated in the RFO or not, is considered a bilateral negotiation and not entered into pursuant to a competitive RFO. It is likely, however, that SCE would use the results of the RFO (if completed around the same time as the bilateral negotiation) to support the economic evaluation of the bilateral transaction as evidence in a "strong showing."

e) Proposed Transaction Timing for Upcoming RFOs

SCE does not have a stipulated schedule that it follows in issuing RFOs. SCE typically conducts a competitive All-Source energy and capacity solicitation per year, and may conduct a gas solicitation, as needed, in order to manage its Residual Net Long/Residual Net Short

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32 *See* D.07-12-052, p.148.

33 Conditions may necessitate the alteration of the schedule. If this is the case, the revisions will be publicized and applied consistently for all counterparties to ensure fairness.

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(RNL/RNS) energy and RA capacity and TEVaR. In part, the schedule and frequency of future RFOs depends on the success SCE encounters in completing its most recent RFOs.

A host of other related issues will likely drive the objective, timing, number, and size of future RFOs. On the horizon, SCE sees potential for changes in RA counting rules as well as new requirements for certain characteristics from the RA fleet, such as flexible resource attributes necessary to meet net ramping needs, to potentially impact future RFOs.[34] Additionally, SCE will look to continuing its implementation of the Loading Order, which may lead to an increase in future RFOs and which will likely impact the RFO process. Finally, hedging strategies (particularly regarding price risk) may also drive the need for additional RFOs.

While SCE cannot predict the need and schedule of future RFOs, future solicitations will be driven by regulatory requirements, the composition of SCE's portfolio, and market forces, and will be communicated broadly to the market.

6. Evaluation and Selection of Resources Outside of an RFO Process

SCE's offer valuation process generally is the same whether the valuation is conducted within an RFO process or outside an RFO process. The selection process, however, generally differs.

Similar to the valuation for offers within an RFO process described earlier, the valuation of an offer outside an RFO process (*e.g.*, a bilateral offer) involves calculating the expected NPV of the offer. SCE determines the components of the NPV based on the type of bilateral offer being executed.

In the selection phase, SCE generally does not have other bilateral offers as points of comparison for the proposed transaction. SCE compares the NPV of the bilateral offer with the NPVs of offers with similar characteristics (*e.g.*, similar unit heat rates, similar operating

[34] The CAISO and CPUC are currently developing these requirements and have defined "net ramping" as the load ramp net of intermittent resources whose changes in output may exacerbate the gross load ramp.

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characteristics, similar renewable/preferred attributes, similar premium, or strike price) from benchmarks developed from market surveys and/or from the most recent RFOs to ascertain whether a bilateral offer is attractive relative to offers through an RFO process. SCE shall consult with its PRG for all transactions longer than a calendar quarter in duration or executed more than a calendar quarter prior to initial delivery.

7. SCE's Consultation Process With its Procurement Review Group (PRG)

SCE conducts quarterly meetings with its PRG to discuss its forecasts, open position, changes in market conditions from the previous quarter, including natural gas and electric prices, and the hedging strategies going forward. SCE also conducts regularly scheduled meetings with its PRG to address procurement activities prior to launch of solicitations and during solicitations, as required. Additionally, SCE conducts ad hoc meetings as necessary, to discuss current issues with its PRG.

Current participants in SCE's PRG include representatives of the following organizations:

- Commission's ED (*ex officio*)
- Commission's Office of Ratepayer Advocates (*ex officio*)
- The Utilities Reform Network (TURN)
- The Coalition of Utility Employees (CUE)
- Union of Concerned Scientists (UCS)
- California Department of Water Resources (DWR)

SCE provides PRG participants with meeting agendas and materials a minimum of 48 hours in advance of a PRG meeting, unless there are unusual, extenuating circumstances. Following a PRG meeting, SCE provides confidential meeting summaries to PRG participants that include a list of attending PRG participants, including the organizations represented, a list of topics presented and discussed, and a list of information requested or offered to be supplied after the meeting. The

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confidential meeting summary shall be distributed on the earlier of a) 14 days after the PRG meeting, or b) 48 hours before the next regularly scheduled PRG meeting. If, due to unusual circumstances, 14 days will be inadequate time to prepare a meeting summary, SCE may distribute it 21 days after the PRG meeting, but may do so only if it sends an e-mail to the same distribution list 7 days after the PRG meeting informing them of the delay in distribution.[35]

SCE's PRG calendar, which includes dates of scheduled PRG meetings, is publicly available at: https://www.sce.com/wps/portal/home/procurement/review-group-info. This calendar also provides the public with information about the date and time that a specific PRG meeting occurred, the duration of that meeting, the individual PRG participants that attended the meeting (including the name of the organization each individual represented), and a list of items discussed during the meeting that includes only public information.

B. Risk Management

1. Risk Management Policy

SCE's Energy Procurement Risk Management Committee (epRMC) serves as the Company's significant decision making body for energy procurement-related activities and risk management. The epRMC is comprised of the SCE President, the SCE Senior Vice President & Chief Financial Officer, the SCE Senior Vice President of Regulatory Affairs, and the SCE General Counsel. SCE convenes its epRMC on a regular basis to oversee SCE's energy procurement risks. These include, but are not limited to, risks associated with Short-Term, Medium-Term, and Long-Term[36] energy-related obligations for power and capacity (including QF, CHP, and renewable resources), transmission products, natural gas (commodity, transportation, and storage), emissions credits, and ancillary services.

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35 D.12-04-046, pp.65-66.

36 *See infra*, Sheet 29, footnote 40.

(Continued)

The epRMC has the following responsibilities: (1) to provide a forum and a process to identify and understand the critical risks related to energy procurement; (2) to facilitate the management and mitigation of such risks in accordance with Commission directives; (3) to oversee and approve SCE's energy procurement activities; and (4) to establish SCE's energy procurement credit risk policy (Risk Policy) and hedging strategy.

As mentioned above, one of the epRMC's responsibilities is to establish the SCE Risk Policy that governs power procurement activities. SCE developed this policy to ensure that SCE's power and natural gas procurement-related activities are consistent with risk tolerances and risk management objectives established in the Commission decisions on SCE's LTPP, RPS, and other relevant proceedings. The Risk Policy outlines the governance hierarchy, describes the roles and responsibilities for the SCE organizations involved in the procurement process, defines limits for power and natural gas procurement-related transactions and a limit exception process, and describes the process for establishing, monitoring, and managing counterparty credit and collateral resulting from SCE's power procurement activities.

2. Risk Management Strategy

The "Hedging Strategy Process" diagram below describes, at a high level, SCE's approach to risk management strategy. The process is designed to allow SCE appropriate flexibility to adjust its strategy to changing circumstances to best meet customer needs. Goals of SCE's hedging strategy include, in part, rate stability, risk management, cost minimization within an acceptable risk tolerance, and regulatory compliance. Inputs to SCE's process include, but are not limited to, load forecasts, market conditions (including power and gas prices and their liquidity), resource availability, available products, regulatory requirements, and environmental considerations.

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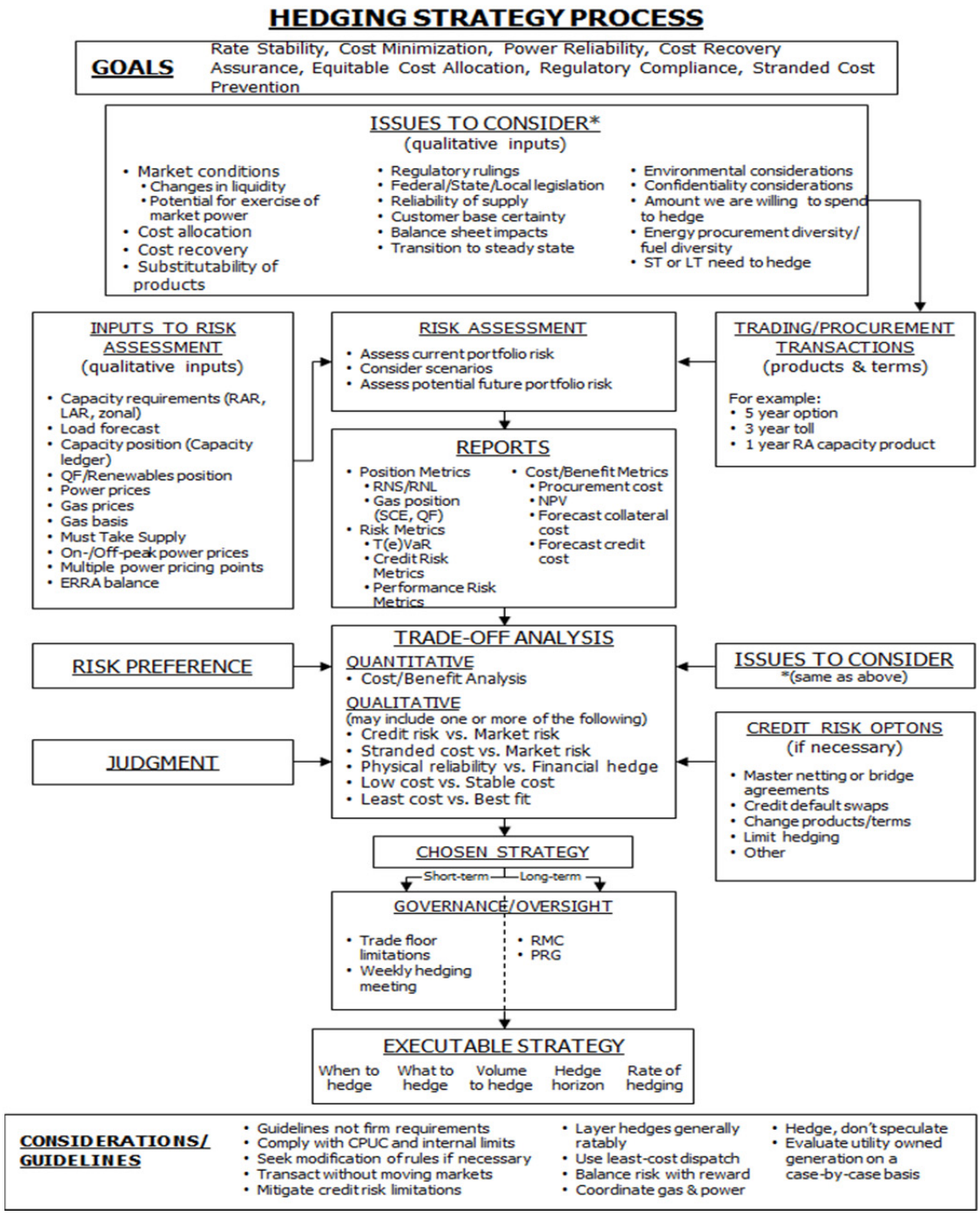
HEDGING STRATEGY PROCESS
GOALS
Rate Stability, Cost Minimization, Power Reliability, Cost Recovery Assurance, Equitable Cost Allocation, Regulatory Compliance, Stranded Cost Prevention
ISSUES TO CONSIDER*
(qualitative inputs)
• Market conditions
• Changes in liquidity
• Potential for exercise of market power
• Cost allocation
• Cost recovery
• Substitutability of products
• Regulatory rulings
• Federal/State/Local legislation
• Reliability of supply
• Customer base certainty
• Balance sheet impacts
• Transition to steady state
• Environmental considerations
• Confidentiality considerations
• Amount we are willing to spend to hedge
• Energy procurement diversity/ fuel diversity
• ST or LT need to hedge
INPUTS TO RISK ASSESSMENT
(qualitative inputs)
• Capacity requirements (RAR, LAR, zonal)
• Load forecast
• Capacity position (Capacity ledger)
• QF/Renewables position
• Power prices
• Gas prices
• Gas basis
• Must Take Supply
• On-/Off-peak power prices
• Multiple power pricing points
• ERRA balance
RISK ASSESSMENT
• Assess current portfolio risk
• Consider scenarios
• Assess potential future portfolio risk
TRADING/PROCUREMENT TRANSACTIONS
(products & terms)
For example:
• 5 year option
• 3 year toll
• 1 year RA capacity product
REPORTS
• Position Metrics
• RNS/RNL
• Gas position (SCE, QF)
• Risk Metrics
• T(e)VaR
• Credit Risk Metrics
• Performance Risk Metrics
• Cost/Benefit Metrics
• Procurement cost
• NPV
• Forecast collateral cost
• Forecast credit cost
RISK PREFERENCE
JUDGMENT
TRADE-OFF ANALYSIS
QUANTITATIVE
• Cost/Benefit Analysis
QUALITATIVE
(may include one or more of the following)
• Credit risk vs. Market risk
• Stranded cost vs. Market risk
• Physical reliability vs. Financial hedge
• Low cost vs. Stable cost
• Least cost vs. Best fit
ISSUES TO CONSIDER
*(same as above)
CREDIT RISK OPTONS
(if necessary)
• Master netting or bridge agreements
• Credit default swaps
• Change products/terms
• Limit hedging
• Other
CHOSEN STRATEGY
Short-term
Long-term
GOVERNANCE/OVERSIGHT
• Trade floor limitations
• Weekly hedging meeting
• RMC
• PRG
EXECUTABLE STRATEGY
When to hedge
What to hedge
Volume to hedge
Hedge horizon
Rate of hedging
CONSIDERATIONS/ GUIDELINES
• Guidelines not firm requirements
• Comply with CPUC and internal limits
• Seek modification of rules if necessary
• Transact without moving markets
• Mitigate credit risk limitations
• Layer hedges generally ratably
• Use least-cost dispatch
• Balance risk with reward
• Coordinate gas & power
• Hedge, don't speculate
• Evaluate utility owned generation on a case-by-case basis

(Continued)

As indicated in the process diagram, SCE assesses risk to its customers by considering the issues specified and devises a strategy for trading and procurement that takes into consideration the cost/benefit of the various transactions, risk preferences, and best judgment. TEVaR is currently used as one benchmark of risk to SCE's customers. D.03-12-062 required SCE[37] to convene a PRG meeting if its 99th percentile TEVaR reporting measure exceeds 125% of the Commission's established Customer Risk Tolerance (CRT) (*i.e.*, if the TEVaR measure exceeded 125% of CRT).[38] Various actions, including increased hedging, have been recommended, considered, and/or implemented as a result of exceeding the TEVaR threshold. Subsequently, D.07-12-052 ordered the IOUs to adopt the 95th percentile TEVaR reporting measure for CRT comparison purposes.[39] D.12-01-033 also revised the PRG consultation threshold from 125% of CRT to 100% of CRT. SCE's 12-month TEVaR has not exceeded the TEVaR threshold since December 2007.

The Hedging Strategy Process specifies the following key considerations in selecting hedging transactions:

- Hedge, not speculate
- Use guidelines, not firm requirements
- Comply with Commission and internal limits
- Mitigate credit risk
- Layer hedges generally ratably
- Balance risk with reward

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37 *See* D.03-12-062, pp.14-15, OP 3.

38 *See id.* at p.16. The CRT adopted in D.12-01-033 is 10% of SCE's system average rate. *See* Section IV.B. 4 below.

39 *See* D.07-12-052, p.304, OP 21.

(Continued)

- Coordinate gas and power
- Use least-cost dispatch

SCE then executes transactions with the governance and oversight specified in the "Risk Management Policy" section above. SCE reviews traded transactions in its weekly hedging operations meetings, monthly with senior Power Supply and Risk management (and quarterly with the epRMC and its PRG), and executes them within pre-authorized trade floor limitations. Any transactions not classified as "Short-Term"[40] – including longer-term trades, structured transactions, and RFOs – require obtaining appropriate authorization from the epRMC and consultation with its PRG prior to execution.

3. Portfolio Risk Assessment

SCE prepares and submits a confidential monthly risk report to the ED indicating the probability that the cost of the SCE portfolio will have a certain value (*i.e.*, SCE will submit a "distribution" of portfolio costs and the probability that it will achieve the distribution point).[41] The elements in the monthly risk report include a portfolio risk assessment, a portfolio cost report, the time periods covered by the portfolio risk assessment, and SCE's methodologies used in developing portfolio cost distributions. Appendix J provides the format of the monthly portfolio risk assessment report. Monthly portfolio risk assessment reports contain cost distributions, both

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40 "Short-Term Transactions" are defined as transactions with delivery terms up to, and including, one quarter (*i.e.*, three calendar months) in duration and up to one quarter forward. A subset of Short-Term Transactions, "Prompt Month Transactions," are defined as transactions with delivery terms less than or equal to one calendar month, and executed within the time frames that define Prompt Month Electricity and Prompt Month Natural Gas, as applicable. "Long-Term Transactions" refers to transactions with delivery terms equal to or greater than five years in duration. "Medium-Term Transactions" include all transactions with delivery terms less than five years in duration (*i.e.*, not Long-Term Transactions) that either have delivery terms greater than one quarter or are procured more than one quarter in advance of delivery (*i.e.*, not Short-Term Transactions).

41 SCE submits the confidential monthly report by the 15th day of each month. SCE also provides a copy of the confidential monthly report, for information purposes only, to SCE's PRG participants.

(Continued)

including and excluding the forward transactions conducted during the month, in order to indicate the change in the distribution attributable to the new transactions.

The cost components included in SCE's monthly portfolio risk assessment include all SCE supply resources that have cost structures dependent on power and gas market prices. This includes, for example, QF energy payments that are tied to gas prices, gas requirements associated with SCE contracts, energy RNS procurement costs, and energy RNL sales revenues. SCE uses internally developed load and supply forecasts to obtain energy RNS and energy RNL positions. SCE combines these market price-sensitive portfolio components to estimate a probability distribution of portfolio costs. The "width" or "spread" (statistically the standard deviation) of this cost distribution is an indication of the risk of the total portfolio.

a) TEVaR Methodology for Measuring Portfolio Risk Exposure

For a given future time horizon, TEVaR is a measurement of uncertainty of market-sensitive procurement costs within that horizon. The market-sensitive procurement costs[42] are energy procurement costs for power and natural gas that SCE incurs on behalf of its bundled service customers. The market-sensitive procurement costs are expressed as a function of four uncertainties: power price, gas price, load, and supply availability. A stochastic process is developed for each of these uncertainties and simulations of the stochastic process provide sample outcomes of the market-sensitive procurement costs. The sample outcomes are considered a discrete probability distribution for the market-sensitive procurement costs. Various statistical measurements are available from the sample outcomes including expected costs, standard deviation of costs, and designated percentile outcomes. The reported TEVaR measurement is currently

42 GHG allowance cost will be added as a risk factor in SCE's TEVaR management when sufficient market and historical data are available to incorporate into SCE's risk assessment process.

(Continued)

calculated as the difference between the 95th percentile's cost outcome and the expected cost.[43] The tables in Appendix J show that TEVaR is reported over different time horizons.

The following equation gives major elements that contribute to market-sensitive procurement costs.

$$MarketSensitive\ Procurement Cost = \sum_{i=m}^{n} D_i[L_i P^L{}_i - S^G{}_i(P^G{}_i - HR_i G_i - VC_i) + w_i(p_i - P^F{}_i) + j_i(g_i - G_i) + S^U{}_i P^U{}_i]$$

where:

- i is an index that indicates the months over the time horizon of interest, month m to month n.
- D_i is the discount rate obtained from U.S. treasury zero coupon bonds that SCE applies to costs.
- L_i is the load in MWh for month i and is an uncertain variable.
- $P^L{}_i$ is the load weighted average purchase price of SP-15 electric power in dollars per MWh at delivery time for delivery month i and is an uncertain variable.
- $S^G{}_i$ is the quantity of sales of electric energy in MWh during month i from the economic dispatch of gas indexed resources within SCE's portfolio and is an uncertain variable.
- $P^G{}_i$ is the average market price associated with gas indexed sales at delivery time in $/MWh for delivery month i and is an uncertain variable.
- HR_i is the average heat rate in MMBtu/MWh of gas indexed sales from SCE's portfolio during the month i and is an uncertain variable.

[43] D.07-12-052, pp.177-78.

(Continued)

- G_i is the average gas price associated with gas indexed sales at delivery time in $/MMBtu for month i and is an uncertain variable.
- VC_i is the average variable cost, other than gas costs, in $/MWh of gas indexed sales from SCE's portfolio and is uncertain due to the uncertainty of the dispatch.
- w_i is the quantity in MWh of SCE sales and purchases of fixed price contracts in forward markets for delivery month i and is a known quantity; w_i is negative if SCE is a net purchaser and positive if SCE is a net seller.
- p_i is the average transaction price in $/MWh of fixed price contracts in forward markets for delivery month i and is a known quantity.
- P^F_i is the average price of power on delivery date associated with fixed price forward contracts for delivery month i and is an uncertain quantity.
- j_i is the quantity in MMBtu of SCE purchases of fixed price gas contracts in forward markets for delivery month i and is a known quantity.
- g_i is the average purchase price in $/MMBtu of fixed price gas forward contracts for delivery month i and is a known quantity.
- S^U_i is the quantity of sales of electric energy in MWh during month i from the economic dispatch of resources within SCE's portfolio that are not gas based.
- P^U_i is the supply weighted average sale price of SP-15 electric power in dollars per MWh at delivery time for delivery month i and is an uncertain variable.

The steps for determining 95% TEVaR and associated reporting metrics are as follows:

(Continued)

1. Establish a stochastic process for power delivery time power and gas prices, load and supply availability.
2. Simulate the stochastic process to provide outcomes which are a series of delivery time, power and gas prices, load and supply availability throughout the reporting time horizon.
3. For each outcome, directly calculate the market sensitive procurement costs of the terms $L_i P^L{}_i, w_i(p_i - P^F{}_i), j_i(g_i - G_i)$.
4. For each outcome, use the power and gas price series to estimate a simulated economic dispatch along with procurement revenues and costs.
5. For each outcome, calculate the procurement revenues and costs for additional portfolio elements.
6. For each outcome, sum the results of steps 4, 5 and 6 and apply the discount rate to determine total present value of procurement costs of that outcome.
7. From the set of all procurement cost outcomes, calculate the various reporting metrics: expected procurement costs, standard deviation of procurement costs and 95% TEVaR.

b) Use of TEVaR in Procurement

Since SCE uses TEVaR as the measure of risk in SCE's portfolio, SCE can use changes to TEVaR to measure the reduction in risk resulting from forward transactions. Appendix J contains an example of current TEVaR results.

c) Submittal of Portfolio Risk Assessment to the Commission

Appendix J also provides the format of SCE's monthly portfolio risk assessment report. SCE submits the report to the Commission by the 15th of each month (or the first business day following the 15th if the 15th falls on a weekend or holiday). SCE establishes the stochastic process

(Continued)

for power and gas prices (*i.e.*, the trade date of the forward curves used for portfolio evaluation) around the last trading week of the month prior to submittal of the report. SCE fixes the portfolio used to calculate the risk metrics on the same date that the stochastic process is set.

While SCE endeavors to issue error free reports, there is a significant level of complexity associated with the preparation of the Risk Assessment report and errors do occasionally occur. SCE will inform the Commission of reporting errors as follows. If errors are greater than 2% of the assessed risk, but less than 10% and do not alter the risk status with respect to the CRT metric, SCE will identify and enclose the corrections in the next regularly scheduled monthly risk report following the discovery and correction of the error. Alternatively, if the error is 10% or greater, or if the correction causes a change in the status with respect to the CRT metric, SCE will refile the report as soon as the corrections have been made.

4. Customer Risk Tolerance

The CRT is a rate in cents/kWh that the Commission adopted as an indicator of customer tolerance to rate increases related to market-sensitive procurement costs as defined in the monthly risk report. The Commission has adopted a periodic update to SCE's CRT as part of SCE's biennial AB 57 BPP filings using a fixed percentage risk tolerance factor multiplied by the ERRA portion of SCE's then-existing system average rate.[44] Appendix J contains the derivation of SCE's CRT, including the fixed percentage risk tolerance factor utilized in this AB 57 BPP.

SCE calculates its CRT every month using a rolling forward 12-month period.

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44 D.12-01-033, p.23. SCE uses its bundled average rate as the equivalent of SCE's system average rate. D.12-01-033, pp.23-24 and 27, provides that the calculation of the CRT will be updated every two years in each AB 57 BPP filing. If the AB 57 BPP filing is delayed or not made, SCE will update its CRT two years from the approval of its conformed filing of the previous AB 57 BPP via a Tier 1 Advice Letter. If there is no AB 57 BPP filing that is usable for this purpose, then the two years will run from the date of Commission approval of the previous CRT.

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1. A base load scenario in kWh for the appropriate rolling forward 12-month period is prepared.
2. The total load is then multiplied by the current CRT rate, which is expressed in cents/kWh. This represents the CRT that is compared to the monthly TEVaR calculation.

The main use of the CRT is for monthly risk reporting on SCE's portfolio. SCE consults with its PRG whenever the 95% TEVaR metric exceeds the CRT. In such cases, SCE and its PRG might discuss possible actions that SCE can take within the framework of SCE's AB 57 BPP to reduce 95% TEVaR.

5. Credit and Collateral Requirements

a) Creditworthiness

Credit risk is the risk that a counterparty to a transaction may be unable or unwilling to meet its payment or performance obligations under the contract. For example, SCE could enter into a contract to procure electricity at a fixed price, and then find that the price of electricity subsequently rises. If the counterparty fails to supply energy as required under the terms of the contract, SCE may be forced to make up the difference in the spot market or under a new contract at a higher price. Parties attempt to minimize the credit risk they face by maintaining their exposure below a certain limit or by requiring counterparties to post collateral if their exposure exceeds a negotiated limit.

To protect against an economic loss as a result of a counterparty's failure to perform, SCE generally requires counterparties to provide collateral for the benefit of SCE whenever the estimated loss SCE would face for a counterparty's non-performance (*i.e.*, SCE's exposure) exceeds a predetermined amount.

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Even if a counterparty has posted or agrees to post collateral, there are still non-performance risks, such as a counterparty declaring bankruptcy. Once a company is in bankruptcy, an automatic stay may prevent the use of pledged collateral absent court approval. In addition, if collateral is received by SCE within a 90-day period prior to the bankruptcy filing, the collateral could be subject to recapture by the bankruptcy court if deemed a preferential transfer.

SCE's Credit Policy and risk mitigation measures described herein in this Section enable SCE to deal flexibly with these types of credit and counterparty risks in the energy procurement market.

b) Credit Limits for Energy Procurement and Related Transactions in the Ordinary Course of Business

SCE is authorized to enter into enabling agreements with counterparties in the ordinary course of business subject to the unsecured credit limits not to exceed those allowed by the Commission.[45] Ordinary course of business transactions are Short-Term transactions for liquid products. When two parties agree to transact with each other, they usually negotiate an enabling agreement appropriate for the intended transaction. These agreements are typically modified with contract terms mutually agreed to by both parties to the enabling agreement. These enabling agreements define the general rights and responsibilities of each party. Generally, as each individual transaction is executed, a confirmation is generated outlining the specific details of that particular transaction.

The following are enabling agreements that SCE has used or may use to transact under:

- The International Swaps and Derivatives Association Agreement (ISDA): Facilitates trading in financial products, including but not limited to, swaps and options.

[45] D.04-12-048, pp.171-172.

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- The North American Energy Standards Board Agreement (NAESB): Facilitates trading in physical gas.
- The Edison Electric Institute Agreement (EEI): Facilitates trading in electric power.
- The Western Systems Power Pool Agreement (WSPP): Facilitates trading in electric power and other power-related transactions.
- Stand Alone Agreements: Facilitates transmission and emissions-related transactions.

SCE may also include a physical power and/or a physical gas annex to the ISDA, or a physical gas annex to the EEI, in order for counterparties to trade under a single agreement with a single set of terms and conditions. The credit terms, including unsecured credit limits, if any, are negotiated by the parties and are included in the enabling agreement. If applicable, enabling agreements may contain a credit rating table, which denotes an unsecured credit line at each rating category. The unsecured credit limit for a given credit rating may generally be the same for both parties to the contract, or as negotiated by SCE and the counterparty.

For ordinary course of business transactions, the amount of SCE's exposure under a contract is calculated as the dollar value of any product delivered to a counterparty but not yet invoiced, plus accounts receivable, minus accounts payable, plus the mark-to-market (MTM). The MTM is the difference between the current market price of the product and the contract price multiplied by the remaining quantity of product to be delivered under the contract. For ordinary course of business transactions, counterparties will be required to post collateral to SCE for SCE's exposure in excess of an unsecured credit limit assigned by SCE to the counterparty. SCE will be required to post collateral for exposure in excess of an unsecured credit limit assigned to SCE by the counterparty. SCE performs a comprehensive credit review of all counterparties seeking to negotiate an enabling agreement and establishes credit thresholds.

Even though a counterparty will be required to post collateral for exposure above the unsecured credit limit in the enabling agreement, SCE may have additional exposure above the

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unsecured credit limit. Market prices, and therefore exposure, may change between the time collateral is requested from the counterparty and the time the collateral is received by SCE. This is referred to as "posting risk." Generally, enabling agreements call for collateral to be posted within a predetermined number of business days of a request. The posting risk exists in addition to the unsecured credit lines provided for in the enabling agreement. SCE may also have exposure due to a possible difference between the exposure estimated for collateral purposes and the actual exposure. This may occur after termination of the enabling agreement due to a default and the termination payment, as outlined in the enabling agreement, has been calculated. Additionally, there is a risk that market prices will change unfavorably to SCE between the time the enabling agreement terminates and, the time SCE can replace the volumes of the defaulted position. Moreover, exposure could exceed the unsecured credit limit outlined in the enabling agreement if and when the credit rating of the counterparty is downgraded and the unsecured credit limit available at the downgraded rating is less than the exposure amount at the date at which downgrade occurs. Appendix F refers to the unsecured credit limits to which SCE shall be allowed to transact up to in aggregate, either for itself or for the counterparty, so as to facilitate transaction execution or the execution of enabling agreements.[46] SCE calculates the credit exposure to a counterparty for any existing enabling agreements prior to extending credit limits for a new agreement, to ensure the counterparty's aggregate credit limits are in compliance with approved credit thresholds.

In some cases, SCE and the counterparty may refrain from stating unsecured credit limits in executed enabling agreements. In such cases, SCE and the counterparty will extend unsecured credit limits to each other on an informal basis (referred to as "internal limits"). As these limits are not codified in an enabling agreement, revocation of this limit may be arbitrary (*i.e.*, these are not contractual obligations and thus not contractually binding on either party).

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[46] These credit limits were previously approved in D.04-12-048, pp.171-172.

Application of this "internal limit" method may apply to the NAESB and the WSPP. When transacting under internal limits, SCE will be in conformance with this Credit Policy by applying term, volume, and/or pricing limits such that potential exposure is less than the internal limit. In determining the unsecured credit limit, SCE will review each counterparty individually. SCE will consider relevant factors which it believes are important in evaluating credit risk and subsequent, potential exposure. Some counterparties have low credit ratings while others are not rated because they are privately held, are a subsidiary of a larger company, or are a municipality. However, if these counterparties have assets in SCE's service territory or are active in the financial, physical gas, or power markets, it may still be desirable for SCE to transact with them and SCE will consider these factors when determining unsecured credit limits.

c) Credit Terms for Structured Transactions

Structured transactions are Medium-Term or Long-Term transactions, typically for non-liquid products. Structured transactions are typically done under enabling agreements or under a stand-alone agreement.

The Commission has granted SCE continued autonomy to negotiate individual credit support packages with counterparties in the kinds of structured transactions described below. Such credit support packages would include, but not be limited to, liquid collateral (cash or letters of credit), in tandem with various contractual provisions as described below.

In order to hedge customers' market price risk, potentially improve supply reliability, increase operational efficiency, or meet certain statutory or regulatory requirements, SCE may enter into Medium-Term or Long-Term transactions through an RFO process. Examples of such transactions include, but are not limited to, capacity tolling contracts for existing or new generation facilities, transmission contracts, gas supply contracts, gas transportation or storage contracts, renewable energy contracts, and contracts to comply with RA or local area reliability requirements. Many of these contracts are tied to specific facilities or projects.

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If SCE were to require collateral posting to fully cover its exposure above an unsecured credit line, if any, it might prevent SCE from signing needed long-term contracts at reasonable prices. The MTM (and its corresponding impact on exposure) over the life of a long-term contract may result in significant potential collateral requirements.

In many cases, counterparties may not have the liquidity required to fund such large collateral requirements. In other cases, counterparties have been willing to provide collateral, but at a significantly increased price. SCE's Credit Policy allows sufficient operating flexibility, to allow for the fact that the full collateralization requirement of exposure, if required of a counterparty by SCE, may not be possible in certain contracts. As a result, SCE's customers may be subject to increased credit risk.

For structured transactions, instead of the full collateralization requirement, SCE will negotiate a credit support package with counterparties, including liquid collateral (cash or letter of credit) and/or other contractual provisions. Generally, SCE has a preference for liquid collateral since this is the most secure form of collateral. Further, as described below, SCE may pursue additional contractual provisions as alternative security designed to reduce risk. While none of these provisions entirely eliminates the risk of a loss due to contract default, each provides some level of protection to SCE by reducing the potential for uncollateralized exposure.

For structured transactions, the MTM is estimated by a formula agreed to by SCE and the counterparty and stated in the contract. The MTM changes as current market prices change; therefore, for purposes of obtaining collateral, SCE recalculates its exposure in accordance with contract terms as indicated in the enabling agreement, or alternatively, as mutually agreed to by SCE and the counterparty. If structured transactions are executed under an enabling agreement, the exposure may be netted with ordinary course of business transactions exposure, depending on the credit terms of the structured transaction.

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(1) Lien on the Assets

SCE may secure its rights under a contract by obtaining a first lien on the assets of the seller. Generally, the assets have already been pledged to support the financing of the facility or parent company debt. Secured lien holders have the benefit of a senior position at the top of the borrower's capital structure, giving them payment priority and varying degrees of control over the exercise of remedies and the restructuring and bankruptcy process. A lien could be another form of collateral that provides protection against counterparty default or bankruptcy, under certain circumstances.

(a) Attornment Agreements

An attornment agreement is an agreement between the project lenders and SCE that requires project lenders to honor SCE's contract even as they exercise their rights of foreclosure and resale of a generating project. However, an attornment agreement may not provide benefits to SCE's customers if the project goes into bankruptcy, since the lenders will no longer have control of the project. In that event, the bankruptcy court can reject the contract, irrespective of the existence of an attornment agreement.

(b) Additional Forms of Security

SCE has listed above the forms of security that it typically considers for structured transactions. However, SCE cannot anticipate every situation that might arise. SCE therefore may use additional forms of security that provide protections similar to those listed above.

SCE requires flexibility in negotiating the credit support package because each Medium-Term or Long-Term transaction is unique in terms of products, contract terms, and counterparties capable of responding. The credit support package that SCE ultimately negotiates will depend on market conditions such as the amount of competition, SCE's negotiating leverage, and a counterparty's credit support package.

For the above reasons, SCE's credit requirements may vary for each RFO. At the outset or during an RFO process, SCE may set RFO-specific credit requirements or standards that

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counterparties must meet in order to participate in the RFO. Such RFO-specific requirements would be applied in a non-discriminatory fashion to all counterparties submitting offers. In addition, SCE may apply an offer valuation adjustment, such as a credit risk adder, based on the strength of the credit support package offered or the credit requirements placed upon SCE. SCE will implement the setting of minimum credit standards. The models and methodologies used to compute offer valuation adjustments will be implemented in consultation with SCE's PRG and with the approval of the epRMC.

The Credit Policy referred to herein and the unsecured credit limits outlined in Appendix F do not eliminate credit risk, and exposure for some transactions may be significant. Nevertheless, this Credit Policy strikes a reasonable balance between credit risk on the one hand, and addressing customer needs and statutory/regulatory minimum requirements on the other.

d) SCE's Energy Procurement Collateral Exposure Limit

As SCE enters additional longer-term transactions for energy procurement (both physical and financial), which reduce future power and gas price uncertainty, there is a subsequent increase in the exposure that SCE may face. Compounding this issue is the fact that SCE's energy needs will change over time. Additionally, any new contracts to meet load growth may also include contract terms requiring SCE to post collateral when its unsecured credit limit is exceeded.

In D.07-12-052, the Commission addressed SCE's increasing exposure to collateral requirements by approving SCE's request to increase its Collateral Exposure Limit from $1.4 billion to $2 billion.[47] This Collateral Exposure Limit is maintained at $2 billion in this AB 57 BPP.

[47] *See* D.07-12-052, p.161.

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e) Credit and Collateral Risk Mitigation Products

SCE will continue to investigate the purchase of credit and collateral risk mitigation products. Examples of credit risk mitigation products include credit derivatives, credit intermediaries, credit insurance, and similar products to transfer credit risk to another entity. Credit derivatives entitle SCE to a payment in the event the counterparty goes bankrupt or defaults on public debt. Credit intermediaries are creditworthy entities that, for a fee, would step in between SCE and the counterparty to a transaction. Credit insurance would protect SCE against losses due to non-payment from any of a group of counterparties, up to a predetermined limit. All of these products shift credit risk away from SCE's customers to a third party. To date, SCE has had difficulty finding cost-effective credit risk mitigation products, but continues to monitor the market. Collateral risk mitigation products are designed to reduce SCE's liquidity risk associated with posting collateral. For example, SCE would pay a fee to limit or completely eliminate its obligation to post collateral. If SCE finds suitable credit or collateral risk mitigation products, SCE will consult with its PRG before entering into any transactions.

f) Exceptions

SCE is authorized to pursue reasonable exceptions to the Credit Policy where justified by special circumstances. In certain cases, compelling business considerations may affect SCE's granting of credit to counterparties. In those instances where market or operational risk considerations outweigh credit risk, SCE may be required to make exceptions to its Credit Policy. For example, SCE may consider credit parameters outside of its stated guidelines for entities whose credit profile is not accurately measured by credit ratings and/or whose services are deemed essential to the successful operation of SCE's business or to meet regulatory requirements. Examples of entities and instances that merit such special consideration include, but are not limited to, the following:

Highly Rated Counterparties – In certain circumstances, the parties may agree that they will not require collateral posting, regardless of the exposure, for a

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particular transaction. SCE may use this option when the counterparty is highly rated (with a rating of at least A-/A3). A counterparty may be eligible for an unsecured credit line in the form of a Guaranty acceptable to SCE from an investment-grade corporate parent. These agreements may contain provisions that if a counterparty falls below investment grade, collateral will be required. These agreements allow SCE to minimize its collateral requirements. Because the counterparties are highly rated, the additional credit risk is unlikely to be significant.

Governmental Entities – It is reasonable to transact with agencies of the federal government, a state government, or a local government that may not be rated.

Pipelines – Given the relative lack of competing natural gas pipelines serving power generating facilities, SCE is often a "captive customer" and has few alternatives in utilizing certain pipelines. SCE may have to accept some additional credit risk to alleviate potentially significant operational and market risk of not being able to move gas to where it is needed. Fortunately, the risk of non-performance for pipelines is generally considered low because they are providing a regulated service.

Operational Considerations – On occasion, SCE must transact with non-creditworthy entities in cases of system emergencies[48] (such as extreme supply emergencies to protect firm customer load or over-generation conditions). These transactions are generally of short duration and accordingly, the credit risk is limited in magnitude.

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48 In the Fifth Replacement Tariff February 1, 2011, CAISO defines a system emergency as "[c]onditions beyond the normal control of the CAISO that affect the ability of the CAISO Balancing Authority Area to function normally, including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment damage, or tripping of system elements which might result in cascading outages or to restore system operation to meet Applicable Reliability Criteria."

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g) Approval Authority

The Commission has adopted the Credit Policy described herein as part of SCE's Commission-approved AB 57 BPP.[49] SCE's epRMC has also reviewed and approved these policies and risk mitigation measures. Consequently, the Commission has granted SCE (i) the flexibility to negotiate credit terms conforming to the SCE Credit Policy, (ii) the flexibility to amend its Credit Policy without seeking Commission pre-approval, and (iii) pass through treatment back to the customer, for any credit/collateral related losses. Further, SCE will be able to recover through rates any loss due to a default, including but not limited to, the cost of exercising contractual rights and the cost of replacement contracts and all associated expenses.

Additionally, pursuant to Resolution E-4112, which approved SCE's Advice Letter filing (AL 2133-E) on October 18, 2007, SCE was granted authority to incorporate SCE's plans for the purchases and sales of SO_2 allowances and derivatives of SO_2 allowances (collectively SO_2 products) in its procurement plan. The same standards and guidelines approved in AL 2133-E continue to apply.

SCE's Commission-approved Credit Policy also includes physical and financial buy and sell transactions for GHG product types. SCE will manage credit limits and risk within the framework of its Commission-approved Credit Policy and pursuant to additional transactional risk mitigation flexibility allowed under Resolution E-4112, portions of which may be incorporated in whole or in part, as part of SCE credit risk mitigation action plans for GHG transactions and products.

C. Procurement Rules for Transactions

AB 57, at Public Utilities Code §454.5(b)(7), indicates that a utility's procurement plan must include:

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[49] *See* D.12-01-033, OP 1; D.12-04-046, OP 8.f and 8.g. *See also* D.04-12-048, pp.171-172.

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The upfront standards and criteria by which the acceptability and eligibility for rate recovery of a proposed procurement transaction will be known by the electrical corporation prior to execution of the transaction.

Detailed below are SCE's Authorized (1) Contract Duration, (2) Electric, Natural Gas, and Emissions Procurement Products, (3) Transactional Procurement Processes, (4) Procurement Limits and Ratable Rates, and (5) Congestion Revenue Rights Transactions processes, which like the rest of its AB 57 BPP, provide upfront standards and criteria for rate recovery of its procurement transactions.

1. Contract Duration

SCE can enter into contract terms of less than five years, provided the contracts expire within the AB 57 BPP's ten-year planning period (*e.g.*, a contract executed in 2015 must expire on or before December 31, 2024). With respect to contracts with power generation facilities that use once-through cooling, pursuant to D.12-04-046, there are additional restrictions, which are outlined in Appendix I.

2. Authorized Electric, Natural Gas and Emissions Procurement Products

Appendix A provides SCE's most current list of authorized procurement products.

a) Loading Order Preferred Resource Products

SCE has included all Loading Order preferred resource products on the list of authorized procurement products. SCE has clarified and redefined Energy Efficiency (demand side), Demand Response (demand side), and Distributed Generation (DG) (demand side or supply side) (previously identified as Forward Energy (demand side), Capacity (demand side), and On-site energy or capacity, respectively), and added Eligible Renewable Resources (ERR) to the list of approved products. By having the Loading Order preferred resource products as authorized products, SCE is able to clearly define the resources that are subject to the upfront achievable standards of AB 57.

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b) GHG Products

In Track III, Phase 2, of the 2010 LTPP proceeding, SCE sought Commission approval of procurement authority to transact GHG-related products in order to comply with CARB's GHG emissions cap-and-trade program. The Commission issued D.12-04-046 approving SCE's GHG procurement authority, with certain modifications.[50] Appendix A provides SCE's list of authorized GHG procurement products pursuant to D.12-04-046.

In conformance with D.12-04-046, SCE may engage in transactions for the electricity-related GHG products (GHG Products) listed in Appendix A (Table of Authorized Procurement Products). SCE will primarily transact allowances through CARB auctions and transact immediate cash settled (ICS), forwards, and futures of GHG allowances and offsets over exchanges, through brokers, and through competitive RFO processes.

CARB's cap-and-trade program authorizes IOUs to meet a portion of their GHG compliance obligation through the purchase of offsets that comport with CARB's previously-approved offset protocols.[51] Offsets will only be certified as compliant after the fact – that is, once the GHG emission reduction has taken place and has been verified. Once an offset is certified, it can be used to fulfill a compliance obligation. However, unlike an allowance, a CARB-certified offset may have its CARB certification revoked. This revocation can occur even after the offset was accepted by CARB for a compliance obligation, if it was later found to have been certified erroneously, under false pretenses, or if the project from which the offset was derived did not meet CARB's permanence requirement. For this reason, CARB-certified offsets are less valuable than allowances and will likely trade at a discount to allowances. In accordance with D.12-04-046, SCE

50 *See* D.12-04-046, pp.40-59.

51 CARB has developed and approved four offset protocols to screen and register potential offset projects and project developers. Section 95970(a) of the Final Regulation Order requires that an offset must "[r]epresent a GHG emission reduction or GHG removal enhancement that is real, additional, quantifiable, permanent, verifiable, and enforceable." Final Regulation Order, Subarticle 13, § 95970(a), p.153.

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may engage in transactions for CARB-certified offsets in which the seller assumes the risk of invalidation. SCE may also procure offsets on a forward basis if the seller assumes the risk of invalidation, the offsets are CARB certified, and payment for such offsets occurs after they are delivered.

Appendix A provides a detailed list of SCE's currently authorized GHG Products. If changes to the market require other GHG Products not listed in Appendix A, SCE will file an Advice Letter for approval to expand that list.

3. Transactional Procurement Processes

SCE's procurement contracting methods include RFOs, exchanges, brokers, auctions, and bilateral transactions (Appendix C provides a complete list of authorized transaction methods). Below is a description of some of these contracting methods. SCE considers several factors to determine the most effective method for a given procurement objective. These factors include, but are not limited to, liquidity of the product and other market dynamics, number of counterparties transacting in the product, and quantities required by SCE. These factors change over time; thus, SCE may transact for the same product at various times using different contracting methods.

a) Exchanges

An exchange is a central marketplace with established rules and regulations where buyers and sellers meet to trade standardized products at prices that are both visible and representative (*i.e.*, the price is knowable and available to any interested market participant and the posted price and quantity are determinative of the final transaction costs). Exchanges differ from brokers in that exchanges take title to the product being transacted, such that the exchange becomes the counterparty for both the buyer and the seller. This has two benefits. First, the identity of the counterparties is never revealed, providing complete anonymity. Second, because of an exchange's structure and margining rules, credit risk is typically substantially reduced relative to

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transacting with a counterparty in the Over-The-Counter[52] markets. An exchange requires posting of an initial margin amount related to the position taken, which is set based on the product and the volume transacted. As the Mark to Market (MTM)[53] of the transaction changes, additional cash will need to be posted by, or returned to SCE to reflect the change. In addition to the fees the exchange charges, posting the initial and maintenance margin is the cost for reducing credit risk through an exchange. SCE is authorized to use pre-approved exchanges in this AB 57 BPP in order for the transactions to be deemed reasonable prior to contract execution.

An exchange may also permit participants to "clear" certain conforming transactions that were not executed through the exchange initially. In this process, the parties to an Over-The-Counter transaction agree to submit the transaction to the exchange. For a fee, the exchange (*e.g.*, NYMEX via NYMEX ClearPort or ICE via ICE Clear) agrees to take title to the transaction and assumes responsibility for protecting both the buyer and seller from financial loss.

The NYMEX and the Intercontinental Exchange (ICE) are two trading exchanges SCE uses (SCE's authorized exchanges are listed in Appendix D). NYMEX allows SCE to transact certain standardized natural gas products (Henry Hub futures and options). ICE allows SCE to execute standardized electricity and natural gas products including, but not limited to, power financial swaps, NYMEX gas look-alike swaps, and gas basis swaps.

To access both NYMEX and ICE, SCE and other market participants use intermediaries called clearing firms, (Appendix D lists SCE's authorized clearing firms). A clearing firm is a company approved to clear trades through the exchange, and is responsible for the financial commitments of its customers that clear through the firm. Clearing firms charge a fee for

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52 "Over-The-Counter" refers to brokered or direct bilateral transactions that do not take place through an exchange.

53 In economics, "MTM" is the act of assigning a value to a position held in a financial instrument or contract based on the current market price for that instrument, or on a fair valuation based on the current market prices of similar instruments.

(Continued)

performing the clearing function. These fees are small relative to the nominal value of the transactions. SCE can choose a clearing firm on a transaction-by-transaction basis.

b) Brokers

Brokers function similar to exchanges by providing a forum for market participants to trade anonymously with one another. Voice brokers announce bid and ask prices, but not counterparty names, to market participants and match up buyers and sellers based on price. Electronic brokers do the same thing electronically (Appendix D lists SCE's authorized brokers). Brokers therefore facilitate trading by creating price transparency and liquidity in the market. As such, the price brokers provide is knowable and available to any interested market participant and representative of the market at the time of the transaction. Therefore, brokers offer price equivalency to an exchange. Brokers differ from exchanges, however, in that they do not take title to the product being transacted and therefore, do not provide credit support for them. Once a broker matches up market participants, their identities are revealed to each other, but not to the market. The market participants must either be enabled to transact (*see* enabling agreements above) or clear the transaction through an exchange as described above. For example, a broker may match up SCE with a counterparty for a natural gas swap. If SCE is enabled with that counterparty, SCE and the counterparty may consummate the transaction through their enabling agreement, which, among other things, establishes the mutual credit requirements, or agree to clear the transaction through an exchange. If SCE is not enabled with the counterparty, they must clear the transaction through an exchange. For providing these matching services, brokers charge each party a fee. These fees are small relative to the nominal value of the transactions.

Brokers are an excellent means through which to procure standardized products not traded on exchanges (*e.g.*, day-ahead physical power and natural gas, or certain financial products such as SoCal Border Basis). SCE is authorized to use pre-approved brokers in this AB 57 BPP in order for the transactions to be deemed reasonable prior to contract execution. Where practical and possible, SCE obtains multiple broker quotes to ensure SCE pays or receives the market price.

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c) Online Auction Platforms

Online auction platforms connect buyers and sellers on a secure internet site in a structured auction, where the auction participants compete against each other in real time, for a specific product, and on the same terms. An example of a third-party provider of online energy auction platforms is World Energy Solutions, Inc. (WES). Similar to other brokers, WES does not take title to the transaction, but rather, matches the customer (SCE) with a counterparty(ies) offering/bidding the best price for a fee. At the end of the auction, SCE may, or may not, choose to accept any or all of the offers/bids made by the counterparties. Once the transaction is consummated, the deal can be either executed as a bilateral transaction or cleared through an exchange, as agreed to by both parties. Online auction platforms offer an additional method of transacting for SCE and increases SCE's procurement choices, allowing SCE to choose the lowest-cost hedging option for its customers.

d) Bilateral Transactions

SCE enters into master enabling agreements with counterparties to accommodate transactions in the Over-The-Counter markets for products which are not available or otherwise advantageously transacted through a broker or exchange. Bilateral transactions can reduce transaction costs by decreasing or eliminating broker fees, clearing fees, exchange fees, or collateral costs that may be incurred by transacting through other methods. Many terms and conditions of a transaction are set out in the enabling agreements, including procedures and penalties in event of default, force majeure clauses, invoicing, payments, credit and collateral provisions, and methods of handling disputes. Once SCE has entered into an enabling agreement with a counterparty, traders may enter into transactions with that counterparty by simply specifying the product, price, volume, delivery/pricing point, and delivery period.

(Continued)

Under the rules adopted by the Commission in previous procurement plan decisions, SCE is authorized to use direct bilateral contracts[54] for Short-Term Transactions[55] subject to a "strong showing"[56] that these transactions "represent a reasonable approximation of what a transparent competitive market would produce."[57] The "strong showing" requirement for bilateral contracting is waived for Prompt Month negotiated bilateral contracts for non-standard products[58] (discussed below and listed in Appendix B), however SCE must demonstrate that such transactions are reasonable based on available and relevant market data supporting the transaction. SCE is also authorized to use negotiated bilateral contracts to purchase longer-term (*i.e.*, longer than one quarter in duration and/or more than one quarter forward) non-standard products provided it includes a statement in its Quarterly Compliance Report (QCR) filing to justify the need for a non-standard product in each case.[59] SCE is authorized to use negotiated bilateral contracting for natural gas storage and pipeline capacity products where there are five or fewer counterparties who can supply the product.[60] SCE is authorized to enter into bilateral contracts for capacity and energy from generators where the purpose is to enhance Local Area Reliability.[61] SCE is also authorized to enter into bilateral contracts for gas transportation receipt

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54 D.03-12-062, p.39, as clarified by D.04-12-048, FOF 73, OP 15.

55 *See supra*, Sheet 29, footnote 40. The Prompt Month for Electricity is defined as the calendar month following the month for which Day-Ahead power trading is taking place, as dictated by the WECC trading calendar. The Prompt Month for Natural Gas is defined as the nearest delivery month for which NYMEX futures prices are published. For the purpose of determining the term of a transaction, the linkage rule in D.14-02-040, p.40 that may link Short-Term Transactions under this bilateral authority into one Medium-Term Transaction applies only to tolling agreements.

56 D.03-12-062, p.39.

57 D.02-10-062, p.34.

58 D.03-06-067, p.20, OP 3.d.

59 D.03-12-062, pp.39-40.

60 *Id.* at 40.

61 D.04-07-028, pp.17-18.

(Continued)

point rights on Southern California Gas Company's delivery system.[62] The procurement of receipt point rights will benefit SCE's customers by assisting SCE in its effort to maintain continued reliability of electric service. Finally, SCE is authorized to engage in inter-utility energy exchanges provided it is included for review in a QCR filing.[63]

Bilateral transactions are, in some cases, the only means of transacting for a product. This is particularly true for non-standard products. In addition to non-standard products, prices offered bilaterally for standard products may be more attractive than prices offered by brokers or exchanges. The reasons for this are not always apparent to SCE, but appear to be related to customer relationship and confidentiality issues. In such situations, SCE will take advantage of the attractive pricing and document how the consummated transaction compared to pricing and terms available through brokers, and, if possible, exchanges.

As discussed, bilateral transactions for certain products can be cleared through NYMEX ClearPort or ICE Clear for a fee. Alternatively, if an enabling agreement is in place, the parties can settle the transaction with each other directly under the terms of the enabling agreement and save both the fees and margin required by NYMEX ClearPort or ICE Clear. Granting credit further benefits SCE and its counterparties, as it allows the portfolio of transactions to result in posting of collateral only when the credit threshold is exceeded.

An additional benefit of bilateral contracting is that by transacting in this manner, SCE can avoid or delay its transactions from impacting the market. If market participants were to discover that a large power or gas user, such as SCE, entered the market to make a purchase or sale, prices for subsequent transactions could be impacted to the detriment of SCE's customers. When SCE

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62 *See* D.07-12-052, p.300, OP 2; Resolution E-4185, approving SCE's 2006 Conformed LTPP in Advice 2246-E.

63 D.02-12-074, p.7.

(Continued)

contracts with parties directly, fewer market participants are made immediately aware of the transaction and the market may remain relatively unaffected.

(1) Price Support for Bilateral Transactions

SCE may satisfy the strong showing requirement[64] for all bilateral transactions authorized under its AB 57 BPP by providing available and relevant market data supporting the transaction. This may include showing competing price offers, results of market surveys, broker and online quotes, and/or other sources of price information, such as published indices, historical price information for similar time blocks, and comparison to RFOs completed within one month of the transaction. When time or circumstances permit, SCE obtains at least one competing offer for a comparable product (*i.e.*, like time, product type, location, terms and conditions) to that actually transacted. Other sources of price information may include, without limitation, published indices, historical price information for similar periods, and operating costs of SCE's resource portfolio.

In addition, SCE documents system operating conditions to the extent they are relevant and necessary to describe the circumstances surrounding specific real-time transactions. On rare occasions, situations may occur (usually in real time) in which SCE must enter into a transaction, and has no alternative to transacting with a single counterparty. On such occasions, SCE documents and explains the situation in its next QCR filing.

(2) Non-Standard Products

"Non-standard products" are products that satisfy a particular operational or procurement requirement but are not liquidly traded through exchanges or brokers. (Appendix B lists products that currently meet the definition of non-standard product). By designating certain products as non-standard, SCE is able to procure these products bilaterally, subject to adequate support, for

64 D.07-12-052, p.211.

(Continued)

terms longer than one quarter and/or with delivery beginning longer than one quarter forward (*i.e.*, Medium-Term Transactions).

SCE will update this list via Advice Letter as traded markets evolve and SCE determines that revisions (additions or deletions) to this list are required. Because markets are dynamic and the approval of Advice Letters is not immediate, it is in the best interest of SCE's customers for SCE to have the option of entering into transactions for non-standard products not included on the above list prior to making or receiving approval of an Advice Letter filing. Therefore, SCE will make such filings as soon as practicable after determining that the list should be revised, but may enter into transactions for non-standard products in advance of Commission approval of the Advice Letter.

e) RFOs

Another mechanism is to purchase energy and energy-related products through RFOs. The RFO process provides liquidity in a limited market, and is an effective mechanism for entering into transactions. Prior to drafting RFO bid documents, SCE will hold a meeting with the IE, its PRG (or CAM Group, if applicable), and the ED to outline its plans (quantities and types of products they intend to solicit, category definitions if multiple bid categories are envisioned, any unique circumstances to be addressed in the RFO) and solicit feedback. Then, SCE will develop the draft RFO bid documents under the oversight of an IE. The bid documents will include (for internal review by its PRG and ED staff) clear descriptions of the bid criteria (including the rationale for selecting and weighting the criteria) and the evaluation and selection process. The draft bid documents will be vetted through SCE's PRG, and any differences will be resolved with ED staff in advance of the public issuance of bid documents. SCE does not initiate an RFO specifically for new resources, unless formal authorization to do so has been received by the CPUC, which typically occurs through the LTPP process. The evaluation and selection of resources through an RFO process is addressed in Section IV.A.5.

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f) Annual EPA Auction

Pursuant to Resolution E-4112, SCE is authorized to transact via the United States Environmental Protection Agency's annual auction of SO_2 allowances.

g) CARB Auctions

Through the CARB cap-and-trade program, CARB allocates allowances to IOUs at no charge.[65] CARB regulations mandate, however, that these allowances must then be consigned to the CARB auction until sold.[66] The resulting revenue is then credited back to the consigning IOU. The use of this allowance revenue is subject to D.12-12-033 in the CPUC Rulemaking (R.) 11-03-012. The IOUs remain responsible for their GHG compliance obligations, contractual obligations, and electricity market price exposure to GHG prices. They may mitigate this exposure by purchasing allowances from the auction or other GHG Products (as defined in Appendix A) from secondary markets. Pursuant to D.12-04-046, SCE may purchase allowances through the quarterly auctions, and may purchase allowances available after the auction from the Allowance Price Containment Reserve.[67]

h) Transactions with SCE/EIX Affiliates

Pursuant to D.04-12-048, IOUs are permitted to enter into long-term transactions with affiliates, so long as such transactions take place through an open and transparent solicitation process. However, D.04-12-048 stated that no short-term transactions may be consummated with an IOU affiliate, except if conducted through the CAISO, brokers, or exchanges. The Commission did not define "short-term" in the context of this rule. SCE construes "short-term" in this context

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65 *See* Final Regulation Order, § 95890(a), p.103.

66 *Id.* at § 95892(c), p.119.

67 The Allowance Price Containment Reserve is an account managed by CARB filled with a specified number of allowances removed from the overall cap at the beginning of the cap-and-trade program. Compliance entities may purchase reserve allowances for compliance purposes at specified prices through direct quarterly sales. *See* Final Regulation Order, § 95831(b)(4), p.58.

(Continued)

to refer to transactions of up to, and including, three calendar months or one quarter in duration, with delivery start dates up to one quarter forward, which is the definition provided by the Commission in the context of bilateral transactions.[68] SCE is authorized to transact with its affiliates in this AB 57 BPP subject to the Commission's restrictions as summarized in this section.

i) Request for Proposals and Request for Offers by Market Participants

Pursuant to D.12-01-033, the IOUs are permitted to submit bids or offers into competitive solicitations, request for proposals, or request for offers issued by other market participants, including other LSEs.[69] Similar to the rules surrounding existing mechanisms of procurement, the existing IE oversight rules will also apply to these activities.

In addition, pursuant to D.12-04-046, UOG shall not bid into utility-run RFOs for generation.[70] UOG shall be procured only after a corresponding utility RFO has failed. In considering UOG applications submitted by IOUs, the Commission will use criteria comparable to those used to evaluate independently-owned generation.[71]

j) Competitive process via electronic solicitation

Pursuant to D.12-01-033, IOUs may participate in competitive electronic solicitations.[72] These opportunities might include but are not limited to sealed-bid solicitations, and a variety of electronic platforms such as e-mails and instant messaging. None of these processes may involve utility-owned resources. The Commission stated that solicitations may be conducted in a range of electronic media in the future, and found it reasonable for the IOUs to participate.[73] In addition,

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68 *See* D.04-12-048, OP 15. *See also supra*, Sheet 29, footnote 40.

69 *See* D.12-01-033, pp.41-42.

70 D.12-04-046, OP 5.

71 *Id.* at OP 6-7.

72 D.12-01-033, pp.42-43.

73 *Id.* at p.43.

(Continued)

the Commission noted that these would all be competitive solicitations as opposed to bilateral negotiations. However, participation is limited to Short- and Medium-Term products and should not include new utility-owned generation. Standard IE rules do apply in these circumstances, and pre-approval is limited to transactions that are less than five years in length.

4. Procurement Limits and Ratable Rates

a) Forward Procurement Authority

SCE has authority to enter into transactions for natural gas, conventional electrical capacity, and conventional energy, up to ten (10) calendar years forward, subject to limits and ratable rates below. Electric capacity and energy from preferred resources and conventional resources are subject to these ratable rates and procurement limits. SCE's maximum contract duration limit for any single natural gas, electrical capacity or electrical energy transaction is less than five (5) years.

b) Electrical Capacity Ratable Rates and Position Limits

Procurement position limits and maximum rates of transaction (referred to as "ratable rates") apply to electrical capacity transactions for delivery months that occur two or more calendar years beyond the transaction year (*e.g.*, for transactions occurring in 2015, limits shall apply to contract deliveries in 2017 and beyond). To ensure SCE can adequately meet immediate system reliability needs, capacity ratable rates and position limits do not apply to contracts delivering in the current calendar year or the prompt calendar year (calendar year immediately following the current year).

Maximum annual position limits for delivery years two through ten shall be equal to the difference between (1) SCE's forecast electrical capacity requirement to meet its RA requirement (*i.e.*, peak annual hour load using a 1-in-2 year load forecast multiplied by 117%), and (2) the forecast Net Qualifying Capacity (NQC) of SCE's committed resources and planned for preferred

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resources.[74] SCE's procurement of electrical capacity as measured by the NQC of the resource, exclusive of preferred resources, cannot exceed the applicable annual position limit in years two through ten.

Ratable rates shall also apply to SCE's procurement of electrical capacity. The maximum rate of transaction shall equal the annual position limit divided by the number of years between the applicable delivery year and transaction year. For example, the ratable rate for contract deliveries in Year 4 would be one-third of the annual position limit for Year 4 (*i.e.*, Year 4 annual position limit divided by the annual time difference between Year 4 and Year 1). These ratable rates accumulate year-to-year, producing cumulative ratable rate limits for each delivery year equal to those defined in Table E-1 of Appendix E. Furthermore, the ratable rate methodology allows for procurement of two times the ratable rate for delivery Year 2 through Year 5 (*e.g.*, for transactions occurring in 2015, delivery years 2017-2020 are eligible for two times the ratable rate) when certain market conditions are present, subject to the corresponding delivery year's annual position limit. The operative ratable rate limit for delivery Year 2 through Year 5 shall be set as follows:

1. Two times the ratable rate if the prompt 12-month forward on-peak implied market heat rate[75] is less than the two-standard deviation historical high value contained in Table E-2 of Appendix E; and

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74 For purposes of calculating SCE's annual electrical capacity limits and compliance with such limits, preferred resources are EE programs, DR programs, Renewable Sources, QF resources, CHP resources, and Distributed Generation. However, any incremental CHP forecast to be required pursuant to the QF/CHP Settlement is not included in the calculation of SCE's proposed annual electrical capacity limits because the NQC of these incremental resources is unknown at this time.

75 Calculated by dividing the SP-15 on-peak power price by the Topock gas price as provided by published indices and/or brokers' quotes.

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2. One times the ratable rate if the 12-month forward implied on-peak market heat rate is greater than or equal to the two-standard deviation historical high value contained in Table E-2 of Appendix E.

The ratable rate limit for delivery Year 6 through Year 10 is one times the ratable rate.

c) Electrical Energy Ratable Rates and Position Limits

Position limits and ratable rates apply to electrical energy transactions with delivery months beyond the Prompt Month. To ensure SCE can adequately meet the immediate energy needs of its bundled customers, position limits and ratable rates do not apply to contracts delivering during the current month or the Prompt Month (calendar month immediately following the current month). Monthly electrical energy purchase position limits are the gross monthly RNS (*i.e.*, the sum of hourly RNS positions during the month) for each month's on-peak and off-peak period based on economic dispatch of SCE's existing portfolio assuming an IMHR two-historic standard deviations below the base case IMHR forecast. Monthly electrical energy sales position limits are the gross monthly RNL (*i.e.*, the sum of hourly RNL positions during the month) for each month's on-peak and off-peak period based on economic dispatch of SCE's existing and planned-for portfolio assuming a two-standard deviation historical high IMHR. Tables E-3, E-3a, E-4, and E-4a in Appendix E contain SCE's on-peak purchase, off-peak purchase, on-peak sales and off-peak sales position limits for electrical energy, respectively. These limits, filed as monthly quantities, set the maximum allowable net forward position for the on-peak and off-peak purchase and sales transactions for the duration of SCE's 2014 Conformed AB 57 BPP.

Annual rolling-year (*i.e.*, rolling 12-month) ratable procurement limits shall apply to SCE's purchase and sale of electrical energy products. The annual ratable rate shall equal 100% of the sum of the monthly position limits for rolling Year 1, except the Prompt Month (*i.e.*, Months 2 to 12 from the current month), 50% for Year 2 (*i.e.*, Months 13 to 24 from the current month), 33% for Year 3 (*i.e.*, Months 25 to 36 from the current month) and so on as Table E-5 in Appendix E

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shows. The ratable rate methodology will allow for electrical energy purchases of two times the ratable rate for delivery Year 2 through Year 5 when certain market conditions are present as set forth below, subject to the individual monthly position limits. The operative transaction limit for purchases in delivery Year 2 through Year 5 are set as follows:

1. Two times the ratable rate if the prompt 12-month forward on-peak power price[76] is less than the two-standard deviation high value contained in Table E-6 of Appendix E; and
2. One times the ratable rate if the 12-month forward on-peak power price is greater than or equal to the two-standard deviation high value contained in Table E-6 of Appendix E.

The ratable rate limit for delivery Year 6 through Year 10 is one times the ratable rate for purchases. A one-times ratable rate applies for all sales transactions.

Energy-only products transacted during the term of SCE's 2014 Conformed AB 57 BPP shall count against the energy purchase and sales monthly position limits and ratable rate limits. Energy-only products include energy-only tolling contracts, heat rate options, and fixed-price non-renewable energy transactions. The quantities counted against the limit will be the forecasted expected energy output of the contract or resource at the time of evaluation. RA-tolling contracts and firm energy imports that can be used to meet RA requirements shall not count against electrical energy position or ratable rate limits as these products may be required to meet SCE's RA requirement. Additionally, products that do not financially hedge costs or otherwise alter SCE's

76 Market quotes for SP-15 on-peak forwards.

procurement cost TEVaR (*e.g.*, Index-priced electrical energy deals) shall not count against electrical energy position or ratable rate limits.

d) Natural Gas Ratable Rates and Limits

(1) Overview

SCE's gas exposure is comprised of two sub-portfolios: Non-QF and QF.

The Non-QF portfolio is made up of the gas requirements related to SCE's utility-owned generation and gas-fired power plants under tolling agreements with SCE. The gas requirements vary as dispatch responds to market prices. SCE manages both the price risk of Financial and Physical transactions for its non-QF portfolio. The power plants currently under tolling agreement include plants on the SoCal Gas, PG&E, and Kern River Gas Pipeline systems. This requires that SCE manage the physical gas requirements for its portfolio pursuant to the balancing rules and physical gas constraints of each of those systems.

The SCE QF Portfolio represents the financial gas exposure related to SCE's QF contracts. Many of SCE's QF contracts have terms that index the energy price to the price of gas or a Heat Rate (HR) payment mechanism. SCE converts this price risk into the equivalent units in natural gas price exposure. Since SCE does not purchase the physical gas for QFs, SCE must use financial gas instruments to manage price risk for this portfolio. This portfolio is at present almost entirely "must take."

In addition to gas purchases, gas sales may become necessary or desirable due to changing system or market conditions. For example, a reduction in forecasted load or power price could result in previously purchased gas becoming surplus, enabling SCE to sell gas. For example, SCE would reasonably purchase gas to fuel a generator dispatched to support a forward sale of electrical energy (a spark spread sale) when the generator would provide the energy more economically than market purchase at forecasted market prices. If electrical energy market prices subsequently decreased while the gas prices remained the same (or increase), it becomes economic to buy electrical energy on the market to support the forward sale instead of operating the gas-fired

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generator. If SCE purchased the electrical energy, the unburned gas would create a long gas position. SCE could sell the surplus gas (a spark spread purchase) to recover the gas purchase cost. A similar situation arises when the IMHR (defined as the ratio of the market price of power to the market price of gas) decreased and certain power producing resources in SCE's supply portfolio are no longer economic. If the lack of these resources then make SCE's power position short, SCE's power traders can buy fixed price power from the market to hedge the short position. SCE's gas traders would then sell an appropriate amount of fixed price gas to effectively lock in a production cost for this power below the portfolio's cost to produce it. In another example, if the effectiveness (delta) of SCE's gas hedges increases due to market price changes (*e.g.*, gas options become more in the money), and this causes SCE to be over its hedging targets to maintain its 12-month 95% TEVaR within the CRT threshold, SCE may sell off a portion of its gas hedges.

The foregoing examples show that gas sales are an integral part of operating an electrical system that includes significant gas-fired generation in a least-cost manner under dynamic market conditions.

(2) Position and Ratable Rate Limits

Procurement position limits and ratable rates apply to natural gas transactions with delivery months beyond the Prompt Month. SCE shall net purchases and sales of natural gas for purposes of assessing compliance with its procurement limits. Monthly natural gas position limits are the sum of SCE's forecast gas requirements minus delta adjusted hedges in SCE's portfolio for each month assuming a 2-standard deviation high implied market heat rate based on (1) economic dispatch of SCE's existing portfolio; and (2) an equivalent volume of natural gas that would be required to serve SCE's forecast net-short electrical energy position. Table E-7 in Appendix E contains SCE's natural gas purchase position limits. These limits, filed as monthly quantities, set the maximum allowable net forward position for natural gas.

Rolling-year (*i.e.*, rolling 12-month) ratable procurement limits shall apply to SCE's net purchases and sales of natural gas. The annual ratable rate shall equal 100% of the sum of the

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monthly position limits for Year 1 (*i.e.*, Months 2 to 12), 50% for Year 2 (*i.e.*, Months 13 to 24), 33% for Year 3 (*i.e.*, Months 25 to 36) and so on, as Table E-5 in Appendix E shows. The ratable rate methodology will allow for net natural gas purchases and sales of two times the ratable rate for delivery Year 2 through Year 5 when certain market conditions are present, subject to individual monthly position limits. The operative transaction limit for net purchases and sales in delivery Year 2 through Year 5 are as follows:

1. Two times the ratable rate if the prompt 12-month forward natural gas price[77] is less than the two-standard deviation high value contained in Table E-8 of Appendix E; and
2. One times the ratable rate if the 12-month forward natural gas price is greater than or equal to the two-standard deviation high value contained in Table E-8 of Appendix E.

A one-times ratable rate shall apply for net purchases and sales in delivery Year 6 through Year 10. Natural gas basin and basin derivative contracts shall count against the natural gas monthly position and annual ratable rate limits. Natural gas basis and basis derivative contracts shall not count against the limits, as these products are simply paired with basin contracts to produce a financial hedge at the location corresponding to SCE's price exposure. Paired transactions (*e.g.*, spreads, collars) shall count as a single hedge quantity (one buy and one sell equals one hedge) to measure against the limit and ratable rate. Products that do not financially hedge costs or otherwise alter SCE's procurement cost TEVaR (*e.g.*, Index-priced natural gas

77 This gas price is the sum of the NYMEX Henry Hub futures price and the Topock natural gas basis forward price.

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deals) shall not count against natural gas monthly position or annual ratable rate limits.[78] SCE will measure all countable products at their notional (*i.e.*, not delta-adjusted) contract quantity, but the calculation of SCE's net open position used to set the monthly position and annual ratable rates will delta-adjust all gas products.

(3) Natural Gas Storage and Pipeline Limits

In addition to managing the physical purchase of gas and managing its financial price risk, SCE may require pipeline capacity and natural gas storage (either firm or interruptible). Securing natural gas storage allows SCE to inject gas into storage and then withdraw at a later time to meet reliability and operational needs. SCE can use firm natural gas storage injection and withdrawal rights to mitigate imbalance penalties for operational reasons on pipeline and Local Distribution Company (LDC) systems. Firm natural gas storage rights also provide system reliability, since firm injection and withdrawal are the last non-core services that the LDC will interrupt during a system gas curtailment. Appendix E provides a description of how storage injection, withdrawal and inventory limits are calculated. Table E-9 provides the actual limits.

Similarly, SCE should have the capability to fuel any SCE contract resource up to the full capacity of that resource from whatever location gas can most economically be supplied. Consistent with D.03-12-062, SCE is authorized to obtain gas pipeline capacity to the extent necessary to support delivery of gas from gas receipt points to the generator burner-tip. SCE may contract for gas pipeline capacity to meet each generator's peak annual requirement.[79] If SCE acquires gas transportation capacity that is temporarily not required to transport gas for SCE's

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78 SCE may purchase indexed-price gas to provide contractual assurance of the physical delivery of gas. However, since such a contract does not hedge the price of this gas, the contract should not count against the maximum volume limit, which is intended to be a maximum hedging limit. If SCE later enters into a financial hedge for this physical delivery contract (*e.g.*, by buying a NYMEX futures contract), then at that point the hedge entered into would count against the maximum volume limit.

79 D.03-12-062, pp.28-29.

(Continued)

portfolios, SCE will attempt to market the surplus to the extent allowed by the tariff of the gas transportation provider.

e) SO_2 Allowance Sales Ratable Rates and Position Limits

SCE is not including a limit structure for SO_2 transactions due to the low value of its SO_2 Title IV allowance portfolio.[80]

f) GHG Ratable Rates and Limits

Pursuant to D.12-04-046, SCE's transactions for GHG Products are subject to purchase limits (also referred to as "procurement limits" herein) and transaction rate limits provided in Tables E-10 through E-14 in Appendix E.

(1) Procurement Limits

Per D.12-04-046, GHG Product procurement limits are established separately as Direct Compliance Obligation[81] Purchase Limits and Financial Exposure[82] Purchase Limits. The "Direct Compliance Obligation Purchase Limit" for a delivery year period is calculated as SCE's Total GHG Direct Compliance Obligation forecast at a two-standard deviation high IMHR[83] for that delivery year period. The "Financial Exposure Purchase Limit" for a delivery year period is calculated as SCE's Total GHG Financial Exposure forecast at the expected IMHR for each delivery year period multiplied by the appropriate factor from Table E-11 below.

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80 Total portfolio value is estimated to be approximately $0.64 million as of August 12, 2014.

81 The Direct Compliance Obligation is equivalent to the Direct Compliance Obligation as defined in Appendix 1 of D.12-04-046. This obligation comprises GHG obligations from SCE's UOG, imports, tolling contracts, and QF contracts for which SCE is contractually responsible for procuring allowances.

82 The Financial Exposure is equivalent to the exposure to electricity market prices due to GHG costs. This exposure does not include any exposure due to the Direct Compliance Obligation.

83 The expected IMHR is calculated by dividing the forecast power price by the forecast gas price.

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(2) Transaction Rate Limits

Transaction rate limits establish an annual limit on the amount of GHG Products that can be held for the defined delivery period. Tables E-13 and E-14 in Appendix E set forth the transaction rate limit framework authorized for Direct Compliance Obligation purchases and Financial Exposure purchases, respectively.[84] Transaction rate limits define how quickly the procurement limits can be reached for each forward delivery year period (*e.g.*, only 40% of the procurement limit two years ahead can be purchased in the current year). Although SCE is authorized to sell GHG allowances, no transaction rate limits are established for sales.

In establishing the transaction rate limits, the Commission treated each future year as the applicable "delivery period." SCE's transaction rate limits are calculated for the transaction year assuming that the current and each future year is a unique delivery period. For ease of compliance, SCE will measure all countable[85] GHG Products against the transaction rate limits using their nominal (*i.e.*, not delta-adjusted) contract quantity.

The transaction rate limit for Direct Compliance Obligation purchases for the current delivery year (defined as the current calendar year) shall be calculated as (1) the Direct Compliance Obligation Purchase Limit for the current delivery year, plus (2) the sum of the actual emissions for which SCE is responsible for retiring allowances (or purchasing on behalf of a third party) in previous years up to the transaction year, minus the total allowances or offsets SCE has purchased in previous years up to the transaction year that could be retired against those obligations. SCE will fully account for any purchases from prior years that have been banked for use in a future year.

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84 D.12-04-046, Appendix 1.

85 Countable GHG Products include: allowances or offsets in SCE's CARB registry accounts, fixed-price purchases of allowances and offsets forward contracts, futures contracts, swaps, and options on allowances or offsets. Allowances and offsets contracts priced using a GHG market index do not serve to hedge financial risk against SCE's GHG exposure and will therefore not count against the procurement or transaction rate limits.

(Continued)

For a future delivery year, the transaction rate limit shall be calculated as the Direct Compliance Obligation for that year multiplied by the transaction rate authority for that year.

The transaction rate limit for Financial Exposure purchases for the current delivery year (defined as the current calendar year) shall be calculated as (1) the Financial Exposure Purchase Limit for the current delivery year, less (2) SCE's net purchases of GHG hedges, calculated as the total purchases of GHG hedges in previous years up to the transaction year, minus those GHG hedges sold in previous years up to the transaction year. For a future delivery year, the transaction rate limit shall be calculated as the Financial Exposure for that year multiplied by the transaction rate authority for that year. In this context, GHG hedges are defined as GHG Products purchased or sold for the purpose of hedging SCE's Financial Exposure.[86]

Should either calculation result in a negative number in a given year, SCE's Direct Compliance Obligation or Financial Exposure Purchase Limit for that year will be set at zero. Table E-12 contains the GHG Direct Compliance Obligation and GHG Financial Exposure emissions forecast. Tables E-10 and E-11 contain the GHG Direct Compliance Obligation Purchase Limits and Financial Exposure Purchase Limits, respectively, as established in accordance with the method set forth above.

SCE's ratable rates and procurement limits for GHG-related products are provided in Appendix E.

g) Transaction Compliance Accounting and Limit Updates

Transactions will be deemed to be compliant with SCE's authorized position limits and ratable rate limits if, at time of purchase or sale, the transaction does not cause SCE to exceed its applicable position limit and ratable rate limit. A transition from a two-time ratable rate to one-time ratable rate will not cause any transaction activity that occurred prior to the transition date to

[86] These calculations are equivalent to the equations specified in D.12-04-046, Appendix 1.

(Continued)

be non-compliant with SCE's ratable rate limits, provided the subject transactions complied with the then applicable ratable rate limit when executed.

SCE may file an annual (or more frequent, if necessary) update to its position limits and ratable rate limits in the form of a Tier 1 Advice Letter during years in which SCE does not file an updated conformed bundled procurement plan. This will provide SCE with the opportunity to adjust its position limits and ratable rate limits to reflect changes in SCE's portfolio and updated forecast assumptions. SCE will typically submit the advice filing by October 31st with an effective date of January 1st of the year following the submittal, unless suspended or otherwise instructed by the Commission. SCE shall calculate the updated position limits and ratable rate limits using SCE's Commission-authorized limits methodology.[87]

In accordance with D.12-01-033, SCE shall review its current position relative to the position limits and ratable rates limits on a rolling 24-month forward basis, compare its current positions to its positions in the previous quarter, and include that information in SCE's quarterly PRG meeting.

5. Congestion Revenue Rights (CRR) Transactions

As provided in Appendix G, SCE may transact CRRs in the CAISO's long-term CRR (LTCRR) process, CAISO's annual and monthly CRR allocation and auction processes, and through bilateral means.

6. Convergence Bidding (CB) Transactions

SCE may transact convergence bids in the CAISO's IFM as provided in Appendix H.

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87 The updated limits calculations shall be consistent with the methodology employed in Appendix E. For example, because the CEC's load forecast is part of the approved methodology that set SCE's rates and limits in the 2014 LTPP, SCE may provide its yearly update of its rates and limits in the interim year using the CEC's most updated forecast, such as the CEC's interim demand forecast update, if available.

(Continued)

V.

SCE'S RESOURCE ACQUISITION STRATEGY

In this section, SCE describes its resource acquisition strategy for different resources. For purposes of this discussion, SCE defines "resource acquisition strategy" to mean the path or direction SCE plans to take to obtain resources (demand-or supply-side) to meet the needs of its bundled service customers in a least-cost / best-fit and timely manner while achieving the regulatory policy objectives of the State over the long term and managing the financial risks to retail customers. This strategy will guide how SCE fills out its portfolio need.

A. SCE's Strategy for Procurement of Energy Efficiency and Demand Response

SCE is a strong advocate of cost-effective EE policies, including the Loading Order outlined in the EAP II, which calls for cost-effective EE and DR as the State's preferred means of meeting growing energy needs.[88] From a procurement planning perspective, EE and DR complement each other to create a comprehensive DSM resource: EE supports baseload needs, including demand reduction, while DR helps to meet peaking requirements. SCE will use DSM resources, with a contract duration of less than five years to meet its residual energy and/or capacity needs, where feasible and cost-effective,.

B. SCE's Strategy for Procurement of Renewable Energy

SCE intends to contract for eligible renewable energy resources to follow the State's EAP II Loading Order, where feasible and cost-effective, to meet its residual energy and capacity needs. In addition to the existing RPS-eligible procurement mechanisms, SCE will enter into transactions with a contract duration of less than five years with cost-effective Eligible Renewable Resources. These transactions provide SCE the ability to follow the Loading Order and allow SCE greater opportunities to pursue renewables in a manner that minimizes costs and maximizes value for its

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[88] State of California Energy Action Plan II, Oct. 2005, p. 2.

(Continued)

customers. During those periods where the Eligible Renewable Resources is capable of producing energy and providing capacity but is not under contract, the resource owner may seek a short-term contract.

C. SCE's Strategy for Procurement of Distributed Generation, such as CHP

Pursuant to the State's EAP II Loading Order, SCE intends to further solicit projects that interconnect at the distribution grid level to participate in future All-Source RFOs, where feasible and cost-effective, to meet its residual energy and capacity needs. SCE will enter into transactions with a contract duration of less than five years with cost-effective DG. This may include installation of solar PV on roof tops, interconnecting at the distribution grid level, such as CHP or other renewable projects.

SCE encourages DG as a means of diversifying its energy resources, enhancing environmental quality and encouraging development of projects interconnected at the distribution level.

D. SCE's Strategy for Procurement of CHP and QF Resources

As a result of the QF/CHP Settlement Agreement adopted in D.10-12-035, SCE plans to procure up to 1,402 MW of CHP, its portion of the statewide 3,000 MW target as determined by load share.[89] To date, SCE has procured 1,012 MW of CHP toward meeting its Settlement Agreement MW target.[90]

E. Other Generation Supply Resources

In addition to the resources within the CAISO that are under contract pursuant to SCE's AB 57 BPP, SCE also relies on UOG, long-term renewables, new fossil generation, and imported generation as described below.

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89 *See* D.10-12-035.

90 SCE is on target for MW, but falling short on GHG reduction.

(Continued)

1. Present Utility-Owned Generation

SCE owns and operates generation as listed in Section III.C.1 above.[91] These facilities are all assumed to be available resources in the AB 57 BPP.

2. Long-Term Renewable Contracts

SCE's AB 57 BPP does not address long-term contracts for renewable generation. These contracts are addressed in the RPS Procurement Plan, usually on an annual basis.

3. New and Repowered Fossil Generation

SCE's AB 57 BPP does not address new generation needs for California.

F. SCE's Strategy for Procurement of Imported Generation

Although previous sections describe some of SCE's imported resources, this section describes some features unique to imported generation. South of Path (SP)-26 has over 10,000 MW of import capability through various transmission lines. The majority of the transmission capability is from the Palo Verde, El Dorado, and Mead delivery points from the southwest, as well as the Nevada-Oregon Border (NOB) from the northwest. There is also transmission import capacity from LADWP to SP-26 through Lugo and Victorville and from northern California through Path 26, as well as transmission lines with less capacity, such as Imperial Valley, Blythe and Tijuana.

SCE currently has rights to several generation resources outside of the CAISO control area that must be imported into California to be delivered to SCE's customers. These include SCE's ownership share of the Palo Verde generating station and a 26.9% (525 MW) contracted share of the Boulder Canyon Project (Hoover) generation. SCE also has QF contracts totaling approximately 450 MW in the Imperial Valley Irrigation District (IID) service territory and

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91 SCE also owns generation on Catalina Island. This generation has not been included in the UOG listed within this plan as the load and resources on Catalina Island are not determined within this plan. Catalina is not interconnected to the CAISO and therefore is served strictly from resources located on the island.

contracts with wind resources in Idaho totaling approximately 124 MW and Oregon totaling approximately 845 MW. In addition, SCE periodically procures energy and capacity products from northern California, central California, and outside of California but within the Western Electricity Coordinating Council (WECC) through brokers, exchanges, RFOs or Short-Term bilateral contracts.

Purchases, as well as sales and exchanges, are permitted at various locations throughout the WECC. These include, as examples, Big Eddy, COB/Malin, Four Corners, John Day, Lugo, Mead, Mid C, NOB, Palo Verde, Goshen, Slatt, and Victorville. SCE's AB 57 BPP permits transactions for approved products at these delivery points.

SCE evaluates imported resources by forecasting potential costs and benefits associated with the import. These can include congestion costs, line losses, GHG compliance costs, ancillary services credits, and potential RA value. SCE considers the overall cost of the import prior to transacting. In order for the imported resource to count towards SCE's RA requirement, SCE must also assess the ability to obtain import allocation RA counting rights. Although these import allocation RA counting rights are currently allocated on an annual basis, SCE has grandfathered rights for existing contracts signed prior to March 2006 to guarantee that they count towards SCE's RA requirements. SCE typically focuses on RA-eligible products when entering into longer-term transactions, but may purchase non-RA capacity and/or energy in the shorter term to economically serve the needs of its customers.

VI.
COST RECOVERY ISSUES

This AB 57 BPP does not change SCE's recovery of its fuel and procurement costs. This AB 57 BPP summarizes below how SCE recovers its recorded fuel and procurement costs.

(Continued)

The Commission's three processes for the review and approval of recorded utility procurement costs are:[92]

LTPP: Approximately every two years (subject to change by Commission order), the utility submits an AB 57 BPP to the Commission for its review and approval. The Commission-approved AB 57 BPP establishes the "upfront" standards and criteria that will guide the utility's procurement activities. The utility must execute its transactions in compliance with these approved AB 57 BPP standards and criteria for the Commission to find that its procurement-related expenses are eligible for cost recovery, or subject to traditional after-the-fact reasonableness review. If any transaction does not fit within the Commission-approved procurement authority and the AB 57 BPP standards, the utility must seek the Commission's pre-approval via a separate filing.

QCR Advice Letter Filings: For each quarter of the year, the utility submits a QCR advice letter detailing all transactions that it executed during the quarter. The Commission's audit team reviews these transactions to determine if they were in compliance with the utility's AB 57 BPP, and forwards its recommendations to the ED for approval. If the ED approves the QCR, the utility's transactions are in compliance with the utility's Commission-approved AB 57 BPP , and SCE can recover the related procurement costs through the ERRA balancing account. On the other hand, if the audit team finds any transaction to be non-compliant with the utility's AB 57 BPP , the utility would need to justify that transaction's reasonableness via a separate filing.

ERRA Review Proceeding: In the ERRA Review proceeding, the Commission conducts the following reviews: (1) a compliance review to determine if the utility's daily energy dispatch decisions and related short-term procurement activities (*i.e.*, daily and hourly spot market transactions) were consistent with the least cost dispatch principles set forth in Standard of Conduct No. 4; (2) an accounting review to determine if the utility accurately recorded the procurement expenses that are eligible to be recovered through the ERRA balancing account; and (3) a reasonableness review to determine if the utility reasonably administered its QF and non-QF contracts, and if the operation of its UOG, including maintenance outages, was reasonable.

In addition to the description above, the Commission's D.07-12-052 required that the ED work with the IOUs to develop a streamlined QCR reporting format. This format was put in place

92 *See generally* Appendix to D.10-07-049.

(Continued)

on December 15, 2008 and was utilized beginning Q4 of 2008. SCE continues to submit QCR Advice Letter filings consistent with Commission mandates and the uniform format approved by the ED. In D.14-02-040, the Commission required the ED to work with IOUs to improve the current QCR reporting format. SCE will utilize any new format approved by the Commission as a result of this process. Until then, SCE will utilize the most current approved format.

SCE established the ERRA pursuant to D.02-10-062. The purpose of the ERRA is to record SCE's: (1) ERRA Revenue; (2) UOG fuel costs; and (3) purchased power-related expenses, excluding DWR power contract expenses.

VII.
COMMISSION REVIEW OF IMPLEMENTATION OF AB 57 BPP

As mandated by various procurement-related Commission decisions, SCE files several reports to verify that it has followed the standards set forth in its Commission-approved AB 57 BPP, as well as the Commission's standards of conduct. SCE produces each of these procurement reports in a manner that attempts to show how it followed the applicable "rules." For example, SCE's QCR discusses each item identified by the Commission in its QCR Master Data Request.

A. Monthly Reports

SCE files several monthly procurement-related reports in response to various Commission decisions or Commission staff requests. Brief summaries of these reports are included below.

1. Portfolio Risk Reduction Report

As required by D.02-12-074 and D.03-12-062, SCE submits monthly portfolio risk reports to the Commission and to SCE's PRG participants. The risk report benchmark, TEVaR, is calculated on a 12-month rolling basis for the first 12 forecast months, on a quarterly basis for the next 12 forecast months, and on an annual basis for the last 36 forecast months. If the TEVaR for a particular month exceeds the CRT threshold, SCE must discuss this occurrence with its PRG.

(Continued)

2. Monthly ERRA Report

Pursuant to D.02-12-074, Ordering Paragraph 19, SCE submits monthly reports to the Commission indicating the fuel and purchased power expenses that have been recorded in the ERRA for the preceding month. These ERRA reports not only provide the Commission with a snapshot of the net expense incurred by SCE for a given month, but also inform the Commission regarding the current cumulative over- or under-collection in the ERRA.

3. Standing Data Requests

In response to a February 7, 2003 request from the Commission staff (later supplemented with a March 14, 2004 request), SCE provides the following procurement-related information each month:

- Weekly and monthly on-peak and off-peak weighted average cost of electric procurement, including a breakdown of the cost components (*e.g.*, day-ahead transactions, hour-ahead transactions, bilaterals, QFs, etc.)
- Monthly energy and peak load forecasts for a rolling 12-month period
- Monthly residual net short forecasts for a rolling 12-month period under an economic dispatch scenario, including the number of hours and MWh during sub-periods (super peak, off-peak, shoulder peak) that SCE is long and short
- Monthly long positions by category (*i.e.*, physically long or economically long)
- Monthly average on-peak and off-peak electricity price forecasts and monthly average natural gas price forecasts used to derive the residual net short forecast, including the source for the price series and when the price forecast is updated

B. Quarterly Filings

1. AB 57 BPP Quarterly Compliance Report Advice Letters

SCE submits documentation on a quarterly basis to demonstrate compliance with its approved AB 57 BPP. Additionally, as required by the Commission's Master Data Request, SCE's QCRs include the following topics:

- Identifying the ultimate decision makers approving key procurement transactions and providing the briefing packages presented to such decision makers.

(Continued)

- Explaining the justification and the timing for the procurement processes used to select the transactions.
- Discussing the system load requirements and market conditions underlying the need for the transactions.
- Explaining how the transactions met the goals of the AB 57 BPP's risk management strategy.
- Providing a copy of each new contract executed during the quarter.
- Providing an extensive workpaper record in electronic format, including forecast and market data utilized in making transaction decisions.
- Providing additional analyses when requested by the Commission or the PRG.

Taken together, the report and accompanying workpaper documentation demonstrate SCE's adherence to its AB 57 BPP and the numerous procurement rules adopted by the Commission.[93]

C. Annual Filings

1. ERRA Filings

SCE makes two ERRA filings each year – a compliance filing on April 1st that pertains to the procurement activities during the prior calendar year and a forecast filing on May 1st, which is subsequently updated in early November, that projects SCE's energy procurement expenses for the next calendar year. The April 1st filing examines, among other things, SCE compliance with least-cost dispatch directives, the prudence of SCE's contract administration, the operation of utility-retained generation facilities, and the accuracy of costs recorded in various ERRA accounts.[94] The May 1st filing and November filing update provide the Commission with SCE's best estimate of load, available supply resources, and power and gas purchases and sales needed to minimize SCE

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93 Pursuant to D.12-04-046, OP 13, the Commission staff's audit reports of IOU Quarterly Compliance Reports are made public and can be found on the Commission's website. Along with the audit report, any SCE response or rebuttal to the audit report will be provided as a link to SCE's website.

94 D.12-04-046, p.57, requires that the costs incurred for GHG compliance instrument transactions also be included in the ERRA filing for cost recovery.

(Continued)

hourly long and short energy positions throughout the year. The goal of the forecast is to set rates in a manner that will avoid large over- or under-collections in the ERRA.

D. Biennial Filings

1. Biennial Long-Term Procurement Plan

The Commission's current procurement planning framework requires the IOUs to submit their AB 57 BPPs for the Commission's review and approval in the LTPP every two years.

E. As Needed Filings

1. Non-Conforming Transactions

SCE plans to submit for Commission review and pre-approval in a separate filing any transactions that it wants to pursue that do not comply with the pre-approved procurement authority that the Commission grants via the approval of its AB 57 BPP. Also, to the extent any transaction is found by the Commission's auditors to be non-compliant with SCE's Commission-approved AB 57 BPP, SCE will demonstrate the reasonableness of those transactions to the Commission via a subsequent separate filing.

2. Updates or Modifications to AB 57 BPP

SCE follows the Commission's directives and submits any updates or modifications to its AB 57 BPP via an Advice Letter process. After the BPP is approved by an LTPP decision, SCE's conformed BPP filing shall be submitted via a Tier 2 Advice Letter. If ED does not approve the conformed BPP filing, ED will prepare a Draft Resolution.

Additionally, SCE submits the following Advice Letter filings updating its AB 57 BPP:

- SCE may file an annual (or more frequent, if necessary) update to its position limits and ratable rate limits in the form of a Tier 1 Advice Letter during years in which SCE does not file an updated conformed bundled procurement plan. This will provide SCE with the opportunity to adjust its position limits and ratable rate limits to reflect changes in SCE's portfolio and updated forecast assumptions. SCE will typically submit the advice filing by October 31st with an effective date of January

(Continued)

1st of the year following the submittal, unless suspended or otherwise instructed by the Commission. SCE shall calculate the updated position limits and ratable rate limits using SCE's Commission-authorized limits methodology.[95]

- D.12-01-033, pp.23-24, provides that the calculation of the CRT will be updated every two years in each AB 57 BPP filing. If the AB 57 BPP filing is delayed or not made, SCE will update its CRT two years from the approval of its conformed filing of the previous AB 57 BPP via a Tier 1 Advice Letter. If there is no AB 57 BPP filing that is usable for this purpose, then the two years will run from the date of Commission approval of the previous CRT.

[95] The updated limits calculations shall be consistent with the methodology employed in Appendix E.

(Continued)

Attachment C

SCE's Proposed 2014 AB 57 Bundled Procurement Plan Appendices

(Public Version)

Southern California Edison

Rosemead, California (U 338-E)

SOUTHERN CALIFORNIA EDISON COMPANY'S

PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN

APPENDICES

ATTACHMENT C

CLEAN PUBLIC VERSION

Southern California Edison

Rosemead, California (U 338-E)

SOUTHERN CALIFORNIA EDISON COMPANY'S
PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN
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SOUTHERN CALIFORNIA EDISON COMPANY'S

PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN

APPENDICES

Appendix A

Authorized Procurement Products for Energy and Energy-Related Products

(Continued)

Southern California Edison

Rosemead, California (U 338-E)

SOUTHERN CALIFORNIA EDISON COMPANY'S

PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN

APPENDICES

Authorized Procurement Products

Product / Transaction	Description	Benefit /Cost
Energy Efficiency (demand side)	The implementation of load-reducing measures for electrical customers	Reduces load and mitigates energy price risk. Meets the State's Loading Order.
Demand Response (demand side)	Ability to reduce electrical consumption from specified electrical customers at specified times	Provides load reduction when needed and mitigates energy price risk. Meets the State's Loading Order.
Eligible Renewable Resource (ERR)	An ERR is a generating facility that meets all the criteria set forth in Public Utilities Code Section 399.12, Public Resources Code Section 25741, and the California Energy Commission's "Renewables Portfolio Standard (RPS) Eligibility Guidebook" (Seventh Edition), publication # CEC-300-2013-008-ED6-CMF, posted May 17, 2013, which is available at http://www.energy.ca.gov/renewables/documents/.	Helps meet energy needs and can mitigate energy price risk. Meets the State's Loading Order, supports the RPS goal of 33% by 2020, and provides GHG benefits.
Distributed Generation (DG) (demand side or supply side)	Energy or capacity products on the customer side of the meter or in front of the meter, interconnected at the Distribution grid level such as combined heat and power (CHP)	Can provide load reduction and lowers energy price risk. Meets the State's Loading Order.
Forward Spot (Day-Ahead & Hour-ahead (purchase, sale, or exchange)	Purchase pre-scheduled energy or load reductions at either a fixed-price or index-based price	Needed to balance short-term load/resource changes/ Vulnerable to price volatility
Real-time (purchase or sale)	Energy imbalance transactions or load reductions	Balances Short-term needs/ Vulnerable to price volatility

(Continued)

SOUTHERN CALIFORNIA EDISON COMPANY'S Sheet A-2

PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN

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Product / Transaction	Description	Benefit /Cost
Forward Energy (purchase or sale)	Contracts entered into in advance of delivery time, includes block/forward products (*e.g.*, fixed amounts of energy over a specified period of time (*e.g.*, 7x24, 6x16, super-peak, and shaped products) Could be fixed price or index-based price	Reduces price risk / Risk that prices will be below contracted rate (for purchases)
Futures Contract	An agreement to make or take delivery of a particular commodity or financial instrument at a pre-determined price in the future. Futures are distinguished from generic forward contracts in that they contain standardized terms, trade on a formal exchange, are regulated by overseeing agencies, and are guaranteed by clearinghouses. Also, in order to ensure that payment will occur, futures have a margin requirement that must be settled daily.	Similar to forwards in that they reduce price risk by locking in a fixed cost of gas on a forward basis. However, there is always a physical delivery component associated with a futures contract which must be closed out prior to contract expiration.
Resource Adequacy (RA) Capacity Only (purchase or sale)	The product is capacity meeting the Commission's Resource Adequacy requirements. Does not convey any energy attributes to the buyer.	Allows trading of capacity to meet RA or local RAR obligations.
Tolling Agreement	Type of capacity product where buyer hedges fuel cost risk by providing the gas supply, transportation, and storage	Reduces peak price risk / Buyer pays reservation or capacity charges, and is open to gas price risk
Peak for off-peak exchange	Trades peak energy for off-peak energy (x peak MWH < y off-peak MWH)	Reduces peak price risks / Increases off-peak price risks
Seasonal exchange	Buyer receives peak energy in Summer and returns peak energy in Winter	Reduces summer price risk /Increases winter peak price risk
Call (or put) option (purchase or sale)	The right but not the obligation to buy (sell) an underlying asset at some pre-specified price by some pre-determined point in time. May be purely a financially settled instrument or an option to buy (sell) some physical underlying commodity or asset. Options may be combined with other options or swaps to hedge a wide variety of positions.	Sets a cap (floor) on the purchase price of an underlying asset at the expense of paying an option premium (fee)

(Continued)

SOUTHERN CALIFORNIA EDISON COMPANY'S Sheet A-3

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Product / Transaction	Description	Benefit /Cost
Financial swap (purchase or sale)	An agreement between two counterparties to exchange cash flows for the mutual benefit of the exchangers. Usually, one leg involves quantities that are known in advance (*e.g.*, the "fixed leg") the other involves quantities that are uncertain or variable (*e.g.*, the "floating leg"). However, a floating leg versus a floating leg swap may be structured as well, *e.g.*, gas daily index versus first of the month index.	Swaps out one type of risk exposure for another. In a fixed for floating swap: locks in a fixed price (reduces price risk) / Risk that prices will be lower than contracted price (for purchases)
QF Fixed for SRAC Floating Swap (purchase)	An agreement between two counterparties to exchange cash flows for the mutual benefit of the exchangers. Usually, one leg involves quantities that are known in advance (*e.g.*, the "fixed leg") the other involves quantities that are uncertain or variable (*e.g.*, the "floating SRAC leg").	Provides an opportunity for SRAC-based QF pricing to be converted to a fixed price eliminating gas price risk.
Insurance (Counterparty credit insurance, cross commodity hedges)	Buyer can insure against various adverse events (such as extreme temperature, a generating unit failure, or counterparty default, among others), to reduce price risk	Insurance policies can reduce price risk, but increase energy costs by the amount of the insurance premium
Electricity Transmission Products (Purchase or Sale)	Arranged through the California Independent System Operator (CAISO) and with non-ISO transmission owners, and including Congestion Revenue Rights (CRRs). Also includes purchase or sale of transmission rights or use of locational spreads.	Reduces price risk associated with varying transmission conditions.
Long-Term Congestion Revenue Rights (LT-CRRs)[1]	LT-CRRs with terms of up to 10 years.	LT-CRRs provide hedges of up to 10 years against congestion costs under the CAISO's Market Redesign and Technology Upgrade (MRTU) market.

[1] *See* Resolution E-4134, dated Dec. 6, 2007, for a full description of the upfront and achievable standards and criteria for SCE's procurement of LT-CRRs under its AB 57 BPP.

(Continued)

SOUTHERN CALIFORNIA EDISON COMPANY'S Sheet A-4

PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN

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Product / Transaction	Description	Benefit /Cost
Import Counting Right (purchase or sale)	Conveys the right to import capacity at an intertie for RA-counting purposes only. Does not convey physical capacity of the tie or of a generating resource, nor the energy output from a generating facility.	Allows the buyer to obtain import counting rights, which can then be combined with an RA-countable import resource to obtain RA credit
Gas Transportation Receipt Point Rights (Purchases and Sales)	Provides buyer with firm delivery or first priority for delivery of natural gas at specified points on Southern California Gas Company's delivery system.	Assists SCE in its effort to maintain continued reliability of electric service for its customers.
Gas Transportation Transaction (Purchases and Sales)	Buyer contracts for transportation of gas to a determined delivery point, at a set price (could be fixed or variable) over a specified time-frame	Reduces price risk associated with gas transportation (and therefore, limits some electric generation price risk for gas-fired units)
Gas Storage	Buyer reserves gas storage capacity for a defined price	Hedges price risk associated with gas storage
Gas Purchases and Sales	Transactions on a daily, monthly, multi-month, or annual block basis	Used to hedge fuel cost risk associated with capacity contracts
Ancillary Services	Replacement reserve, regulation up, regulation down, spinning-reserve, non-spinning reserve	Needed to assure system reliability
Structured Transactions	Combine one or more product types, varying expiration dates, tiered prices, etc.	Tailor hedges to match your exposure.
Emissions Credits futures or forwards	Provides right to purchase emissions credits at a fixed price.	Hedge exposure to emissions limits resulting from contractual terms.
Weather triggered options	Any transaction otherwise authorized with payment/exercise rights based on weather.	Tailor hedges to match exposure correlated with weather conditions.
Forecast Insurance	Payment to SCE occurs in case of deviations of weather from forecast.	Hedges costs resulting from inaccurate forecasts.

(Continued)

SOUTHERN CALIFORNIA EDISON COMPANY'S Sheet A-5

PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN

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Product / Transaction	Description	Benefit /Cost
SO_2 Allowances[2]	Credits ("Allowances") established under the 1990 Acid Rain Program amendments to the U.S. Clean Air Act to reduce sulfuric emissions from electric power plants and other SO_2 sources. Under the EPA emission allowance trading program, regulated sources of SO_2 emissions are required to relinquish one SO_2 Allowance for each ton of SO_2 emitted in the previous year.	Trading of SO_2 Allowances furthers the intentions of U.S. Acid Rain Program of 1990. Net proceeds from the sale of SO_2 Allowances benefit bundled service customers.
SO_2 Allowance (Immediate Cash Settled) (purchase or sale)	Purchase or sale of SO_2 Allowances that are delivered within a few days of the transaction	Trading of SO_2 Allowances furthers the intentions of U.S. Acid Rain Program of 1990. Net proceeds from the sale of SO_2 Allowances benefit bundled service customers.
Forward SO_2 Allowance (purchase or sale)	Purchase or sale of SO_2 Allowances that are delivered at a future pre-determined date, could be fixed price or index-based price	Trading of SO_2 Allowances furthers the intentions of U.S. Acid Rain Program of 1990. Net proceeds from the sale of SO_2 Allowances benefit bundled service customers.
Options on SO_2 Allowances (call or put options) (purchase or sale)	The right but not the obligation to buy (sell) an underlying asset at some pre-specified price by some pre-determined point in time. May be purely a financially settled instrument or an option to buy (sell) some physical underlying commodity or asset. Options may be combined with other options or swaps to hedge a wide variety of positions.	Sets a cap (floor) on the purchase price of an underlying asset at the expense of paying an option premium (fee)

2 Resolution E-4112, dated Oct. 18, 2007, which approved Advice 2133-E.

(Continued)

SOUTHERN CALIFORNIA EDISON COMPANY'S Sheet A-6

PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN

APPENDICES

Product / Transaction	Description	Benefit /Cost
SO2 Allowance Futures (purchase or sale)	Purchase or sale of SO2 allowances (*i.e.*, Sulfur Financial Instrument (SFI) Futures) that are delivered at a future pre-determined date. Futures are distinguished from generic forward contracts in that they contain standardized terms, trade on a formal exchange, are regulated by overseeing agencies, and are guaranteed by clearinghouses. Also, in order to insure that payment will occur, futures have a margin requirement that must be settled daily.	Allows trading of allowances to meet GHG compliance obligations and price risk management
Immediate Cash Settled (Spot) GHG allowance[3]	Purchase or sale of GHG allowances that are delivered within a few days of the transaction.	Allows trading of allowances to meet GHG compliance obligations.
Forward GHG allowance[4]	Purchase or sale of GHG allowances that are delivered at a future pre-determined date.	Allows trading of allowances to meet GHG compliance obligations and price risk management.
Futures GHG allowance[5]	Purchase or sale of GHG allowances on approved exchanges that are delivered at a future pre-determined date. Futures are distinguished from generic forward contracts in that they contain standardized terms, trade on a formal exchange, are regulated by overseeing agencies, and are guaranteed by clearinghouses. Also, in order to insure that payment will occur, futures have a margin requirement that must be settled daily.	Allows trading of allowances to meet GHG compliance obligations and price risk management.

3 Added per D.12-04-046, Ordering Paragraph (OP) 8.

4 *Id.*

5 *Id.*

(Continued)

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PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN

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Product / Transaction	Description	Benefit /Cost
Immediate Cash Settled (Spot) CARB-certified GHG offset with Seller liability[6]	Purchase or sale of GHG offsets that are delivered within a few days of the transaction	Allows trading of offsets to meet GHG compliance obligations.
Forward CARB-certified GHG offset with Seller liability[7]	Purchase or sale of GHG offsets that are delivered at a future pre-determined date.	Allows trading of offsets to meet GHG compliance obligations and price risk management

6 *Id.*

7 *Id.*

(Continued)

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APPENDICES

Appendix B

Authorized Non-Standard Products

(Continued)

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APPENDICES

Authorized Non-Standard Products

Products
Demand Response Capacity (demand side)
Electricity Transmission Products for non-CAISO transmission
Hourly Electricity Products Traded in the Day-Ahead or Beyond Day-Ahead Markets
Locational Natural Gas Options
Import Counting Rights
Natural Gas Basis Options
Physical Natural Gas Index Options
Sales of Forward Energy from Resources Located Outside the CAISO
Resource Adequacy Capacity Sales
QF fixed for SRAC floating swap

(Continued)

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Appendix C

Authorized Transactional Processes for Energy and Energy-Related Products

(Continued)

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APPENDICES

Authorized Transactional Processes for Energy and Energy-Related Products

Competitive Solicitations/Requests for Offers	A widely distributed/publicly posted request for offers. Consistent products, schedules, and qualifications for bidders are specified.
Generator Open Season	A public offering of capacity by a generator in the interest of soliciting bids.
Inter-Utility Exchange (IUE)	Seasonal and long-term agreements negotiated to reflect the seasonal and locational value of power. Payment is typically non-cash. Opposite peaks in Northwest and Southwest enable large-scale transactions.
ISO Markets	Clearing markets for Day-Ahead, Hour-Ahead, and Real-Time Energy, Imbalance Energy, Ancillary Services, *et al.* with prices determined by bids.
Direct Bilateral Contracting	Contracting directly with a counterparty, approved for: (a) Standard products (except GHG products) with a term of one calendar quarter or less and with delivery beginning less than or equal to one calendar quarter forward (b) Non-standard products (c) Natural gas storage and pipeline capacity where there are five or fewer counterparties who can supply the product (d) Products to enhance local area reliability (e) Gas transportation receipt point rights (f) Inter-utility exchanges
"OASIS": Open Access Same Time Information System	OASIS sites post offers for standard electric transmission products at FERC tariff rates.
On-line Auction Platforms	Energy buyers and suppliers access a secure internet site to engage in a structured auction for a specific product.
Transparent Exchanges and Brokerages	Electronic trading exchanges for transparent prices, including voice and on-line brokers.

(Continued)

Annual EPA Auction	The Environmental Protection Agency (EPA) manages an annual auction that allows market participants to buy and sell SO_2 allowances.
Request for Proposals and Request for Offers issued by market participants[8]	Participation in competitive solicitations issued by market participants which may include generators and other load-serving entities (LSEs) including: (a) Request for Proposals (RFP) (b) Request for Offers (RFO)
Competitive Electronic Solicitations[9]	Participation in competitive electronic solicitations, including, but not limited to, e-mails and instant messaging, that do not involve utility-owned resources.
CARB Auctions[10]	Auctions held by the California Air Resources Board (CARB) or auctions held jointly by the CARB and other jurisdictions.

8 Added per D.12-01-033, p.53.

9 *Id.*

10 Added per D.12-04-046, OP 8.

(Continued)

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Appendix D

Authorized Brokers and Exchanges

(Continued)

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Authorized Brokers and Exchanges

Brokerages

Platform	Platform Sponsors	Date Launched	Date Commission Approved
Amerex	Private Investors	1991	2005
American Energy Risk Management	Private Investors	1991	2006
Automated Power Exchange	Private Investors	1998	
BGC Financial, L.P.	Private Investors	2008	2013
Black Barrel Energy, L.P.	Partners: (99.9%) OTC Global Holdings, L.P and (0.1%) OTC Operating GP, LLC. (also owned by OTC Global Holdings, LP). These entities are owned by Private Investors	2005	2009
Cantor Fitzgerald	Private Investors	1945	2005
Castlebridge Partners LLC	Private investors	1997	2005
CGS Brokerage LLC	Private investors	2003	
Choice Environmental, LLC	Private Investors	2010	2010
Choice Natural Gas, LP	Private Investors	1993	2005
Choice Power, LP	Private Investors	1993	2005
Edge Energy, LLC	Parent: OTC Global Holdings, L.P., Owned by Private Investors	2009	2010
Energy Trade Management GP, LLC	Private Investors	2009	2010
Equus Energy Group, LLC	Private Investors	2010	2010
Evolution Markets	Private Investors	2000	2005
Evolution Markets Futures LLC	Subsidiary of Evolution Markets	2010	2013
GFI Brokers LLC	Private Investors	2000	2006
ICAP Energy, LLC	Intercapital Corporation (London Exchange)	1994	
ICAP United, Inc.	Publicly Traded	2005	2009
INFA Energy Brokers	Private Investors	2005	2006
Intercontinental Exchange (ICE)	Brokers, Energy Companies	2000	2005
IVG Energy, Ltd	Private Investors	2004	2006

(Continued)

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Longevous Capital, LLC	Trading Partners: FCStone, LLC and INTL Hanley, LLC Owned by Private Investors	2010	2012
Natsource Transaction Services LLC	Private Investors	1994	2005
Saddleback Energy	Private Investors	2002	2006
Spectron	Private Investors	1988	2006
TFS Energy Futures LLC	TFS Brokers	1995	2005
Trident Brokerage Services LLC	Private Investors	2003	
Tullett Prebon Financial Services	Subsidiary of Tullett Prebon, plc	2004	2005
Valence Energy, LLC	Parent: OTC Global Holdings, L.P., Owned by Private Investors	2008	2009
Walden Energy, LLC	Trading Partner: Hudson Capital Energy, LLC Owned by Private Investors	2003	2012

On-line Auctions

Platform	Date Launched	Date Commission Approved
World Energy Solutions, Inc.	1999	2009

Exchanges

Platform	Date Launched	Date Commission Approved
ICE	2000	2007
NASDAQ OMX	1971	2013
NYMEX	1882	2005

Clearing Firms

Platform	Date Launched	Date Commission Approved
Citigroup Global Markets, Inc.	1892	2005
Macquarie Futures USA, Inc.	2006	2010
Newedge USA LLC	1987	2005

(Continued)

Southern California Edison

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Appendix E

Procurement Limits and Ratable Rates Tables

(Continued)

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SOUTHERN CALIFORNIA EDISON COMPANY'S
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Sheet E-1

Procurement Limits and Ratable Rates Tables

Table E-1
Electrical Capacity Position Limit and 1 x Ratable Rate (RR) in Megawatts (MW) (Confidential)

Delivery Year	Position Limit (MW)	1x RR in 2015	1x RR in 2016	1x RR in 2017	1x RR in 2018	2019	2020	2021	2022	2023	2024
2015	3,030	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2016	[redacted]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2017	[redacted]	[redacted]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2018	[redacted]	[redacted]	[redacted]	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2019	[redacted]	[redacted]	[redacted]	[redacted]	n/a	n/a	n/a	n/a	n/a	n/a	n/a
2020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	n/a	n/a	n/a	n/a	n/a	n/a
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	n/a	n/a	n/a	n/a	n/a
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	n/a	n/a	n/a	n/a
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	n/a	n/a	n/a
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	n/a	n/a

Table E-2
Electrical Capacity Implied Market Heat Rate Market Condition Measure (Confidential)

Measure	Value
2 Standard deviation high	[redacted]

(Continued)

Table E-3
On-Peak Electrical Energy Purchase Position Limits (MWh)
(Confidential)

Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Jan	[redacted]									
Feb										
Mar										
Apr										
May										
Jun										
Jul										
Aug										
Sep										
Oct										
Nov										
Dec										

(Continued)

Table E-3a
Off-Peak Electrical Energy Purchase Position Limits (MWh)
(Confidential)

Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Jan	[redacted]									
Feb										
Mar										
Apr										
May										
Jun										
Jul										
Aug										
Sep										
Oct										
Nov										
Dec										

Table E-4
On-Peak Electrical Energy Sale Position Limits (MWh)
(Confidential)

Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Jan	[redacted]									
Feb										
Mar										
Apr										
May										
Jun										
Jul										
Aug										
Sep										
Oct										
Nov										
Dec										

(Continued)

Southern California Edison

Rosemead, California (U 338-E)

Table E-4a
Off-Peak Electrical Energy Sale Position Limits (MWh)
(Confidential)

Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Jan	[redacted]									
Feb										
Mar										
Apr										
May										
Jun										
Jul										
Aug										
Sep										
Oct										
Nov										
Dec										

(Continued)

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Table E-5
Electrical Energy and Natural Gas Ratable Rate (RR) Transaction Authority

RR Delivery Month Periods			RR (as a % of the sum of each 12-month period's effective monthly position limit)	
Name	From Delivery Month	To Delivery Month	RR	2x RR
Year 1	Prompt	Prompt +11	100.00%	100.00%
Year 2	Prompt +12	Prompt +23	50.00%	100.00%
Year 3	Prompt +24	Prompt +35	33.30%	66.70%
Year 4	Prompt +36	Prompt +47	25.00%	50.00%
Year 5	Prompt +48	Prompt +59	20.00%	40.00%
Year 6	Prompt +60	Prompt +71	16.70%	n/a
Year 7	Prompt +72	Prompt +83	14.30%	n/a
Year 8	Prompt +84	Prompt +95	12.50%	n/a
Year 9	Prompt +96	Prompt +107	11.10%	n/a
Year 10	Prompt +108	Prompt +119	10.00%	n/a

"Year 1" is a rolling 12-month period comprised of the first traded delivery month in the futures / forwards market for that commodity through the following 11 delivery months. This 12-month period, also defined as the Prompt Year, is labeled as "Year 1" in the table. Each subsequent year (*e.g.*, Year 2) is defined in a similar manner, except that the delivery month dates shift one year forward. For example, in January 2015, the prompt month will be February 2015, and the Year 1 contracts will be the February 2015 through January 2016 delivery months, Year 2 contracts will be the February 2016 through January 2017 delivery months, and so forth. When January 2015 elapses and February 2015 commences, Year 1 will consist of the March 2015

(Continued)

through February 2015 delivery month contracts, Year 2 will consist of the March 2016 through February 2017 delivery month contracts, and so on.

Table E-6
Electrical Energy SP-15 On-Peak Power Price Market Condition Measure ($/MWh) (Confidential)

Measure	Value
2 Standard deviation high	[redacted]

Table E-7
Natural Gas Position Limits (MMBtu) (Confidential)

Month	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Jan	[redacted]									
Feb										
Mar										
Apr										
May										
Jun										
Jul										
Aug										
Sep										
Oct										
Nov										
Dec										

Table E-8
Topock Natural Gas Price Market Condition Measure ($/MMBTu) (Confidential)

Measure	Value
2 Standard deviation high	[redacted]

(Continued)

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Table E-9
Natural Gas Storage Limits (Confidential)

Storage Components	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Withdrawal Capacity (MmBtu/day)										
Injection Capacity (MmBtu/day)										
Inventory (MMBtu)										

SCE's storage injection, inventory, and withdrawal limits are based on SCE's monthly gas burn forecast, assuming economic dispatch of SCE's portfolio under an implied market heat rate that is two standard deviations higher than the base case. SCE's maximum firm storage withdrawal limit for the year is calculated as the largest difference between the maximum daily natural gas usage forecast and the average-day gas usage forecast for each month throughout the gas storage year. Similarly, SCE's maximum storage injection limit is calculated identifying the largest difference between the minimum daily natural gas usage forecast and the forecast of average-day gas usage for each month throughout the gas storage year. SCE's annual storage inventory capacity limit is calculated to secure enough inventory for [redacted] days of withdrawal as calculated above (*i.e.*, [redacted] times the Storage Withdrawal Limit). Prior to transacting for storage under a contract having a term of one calendar quarter or longer, SCE will consult with its Procurement Review Group (PRG) relative to its current estimate of its storage needs.

(Continued)

Table E-10
GHG Transaction Rate Authority
Limits on Direct Compliance Obligation Purchases

	Delivery Year					
Transaction Year	2015	2016	2017	2018	2019	2020
2015	100.0%	60.0%	40.0%	20.0%	0.0%	0.0%
2016		100.0%	60.0%	40.0%	20.0%	0.0%
2017			100.0%	60.0%	40.0%	20.0%
2018				100.0%	60.0%	40.0%
2019					100.0%	60.0%
2020						100.0%

Table E-11
GHG Transaction Rate Authority
Limits on Financial Exposure Purchases

	Delivery Year					
Transaction Year	2015	2016	2017	2018	2019	2020
2015	20.00%	10.00%	5.00%	2.50%	0.00%	0.00%
2016		20.00%	10.00%	5.00%	2.50%	0.00%
2017			20.00%	10.00%	5.00%	2.50%
2018				20.00%	10.00%	5.00%
2019					20.00%	10.00%
2020						20.00%

(Continued)

Table E-12
GHG Direct Compliance Obligation and Financial Exposure Forecasts ($MTCO_2e$) [11]
(Confidential)

	Delivery Year					
Exposure Type	2015	2016	2017	2018	2019	2020
Physical						
Financial						

Table E-13
Transaction Rate Limits for GHG Direct Compliance Obligation Purchases ($MTCO_2e$)
(Confidential)*

	Delivery Year					
Transaction Year	2015	2016	2017	2018	2019	2020
2015						
2016	n/a					
2017	n/a	n/a				
2018	n/a	n/a	n/a			
2019	n/a	n/a	n/a	n/a		
2020	n/a	n/a	n/a	n/a	n/a	

*Any GHG compliance obligation net balance remaining at the end of 2014 will be debited/credited against 2014 Transaction Rate Limits.

[11] $MTCO_2e$ = Metric Tons of CO_2 equivalent.

(Continued)

Table E-14
Transaction Rate Limits for GHG Financial Exposure Purchases ($MTCO_2e$)
(Confidential)*

	Delievery Year					
Transaction Year	2015	2016	2017	2018	2019	2020
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	n/a	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	n/a	n/a	[redacted]	[redacted]	[redacted]	[redacted]
2018	n/a	n/a	n/a	[redacted]	[redacted]	[redacted]
2019	n/a	n/a	n/a	n/a	[redacted]	[redacted]
2020	n/a	n/a	n/a	n/a	n/a	[redacted]

*This transaction rate limit already accounts for net purchases of GHG compliance instruments to date for financial exposure hedging purposes, as of 9/10/2014. Therefore, SCE would be allowed to purchase an additional [redacted] tons in the remainder of 2014 and in 2015 for Delivery Year 2015.

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APPENDICES

Appendix F

Unsecured Credit Limits

(Continued)

SOUTHERN CALIFORNIA EDISON COMPANY'S
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APPENDICES

Table F-1
Unsecured Credit Limits (Confidential)

S&P	Moody's	CPUC-Authorized Unsecured Credit Limits
AA- and above	Aa3 and Above	$[redacted] million
A+	A1	$[redacted] million
A	A2	$[redacted] million
A-	A3	$[redacted] million
BBB+	Baa1	$[redacted] million
BBB	Baa2	$[redacted] million
BBB-	Baa3	$[redacted] million
BB+ and Below	Ba1 and Below	$[redacted] million

(Continued)

SOUTHERN CALIFORNIA EDISON COMPANY'S
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APPENDICES

Appendix G

Congestion Revenue Rights

(Continued)

Overview of SCE's Congestion Revenue Rights Acquisition Authorization

The Commission authorized SCE in its 2006 Conformed LTPP (D.07-12-052) and Resolutions E-4122 and E-4134 to acquire CRRs pursuant to specified upfront and achievable standards and applicable criteria. Notably, these standards and criteria include the requirement that CRRs only be obtained to hedge SCE's expected use of the grid. CRRs are designed to operate as a congestion cost hedge in the CAISO's Market Redesign and Technology Upgrade (MRTU) market. SCE will use CRRs as a cost hedge for its expected transmission usage and not as a tool for price speculation. SCE will not obtain CRRs that are unrelated to SCE's expected sources of power to serve its customers. SCE's authorized CRR acquisition standards are specified below.

1. CRR Procurement Products

With the commencement of MRTU market operations on April 1, 2009, the CAISO replaced its Firm Transmission Rights market design with a CRR market design.[12] CRRs are an "obligation" financial right; CRR holders receive congestion payments for positively-valued CRRs and make congestion payments for negatively-valued CRRs. The CAISO allocates a majority of

[12] CRRs are financial instruments only and do not convey any scheduling priority. Instead, the CAISO dispatches resources based upon a Security Constrained Economic Dispatch algorithm. That is, the CAISO will dispatch resources in a least-cost manner subject to transmission system constraints. CRRs are acquired by SCE for the purpose of offsetting potential congestion costs associated with the day-ahead Integrated Forward Market (IFM). Since MRTU utilizes a full network model, CRRs are designated on a source-to-sink basis.

(Continued)

its CRRs to LSEs based upon their historical load share and has a priority nomination process that allows LSEs to renew their CRRs based upon their historical usage of the transmission grid. The CAISO also operates a CRR auction process that is open to all market participants. CRR auctions are conducted after the CRR allocation processes have concluded. The CRR auction process makes available all CRRs that remain available after the conclusion of the allocation processes, as well as any CRRs that are created through the award of opposite flow CRRs in the auction (*i.e.*, CRRs that create counter-flow capacity). The auction and allocation processes occur annually and monthly.

The MRTU market provides for short-term and long-term CRR products. The short-term products consist of monthly and quarterly terms, and are transacted for on a monthly and annual basis, respectively. The long-term CRR (LTCRR) products have a ten-year term and are acquired through the annual allocation process. CRRs may also be transacted bilaterally.

2. CAISO LTCRR Allocation Processes and Procedures

Pursuant to Resolution E-4122, SCE may obtain LTCRRs with a term up to and including 10 years without Commission approval of the specific transactions. Under current CAISO rules, only CRRs obtained in Tier One of the annual CRR process may be converted into LTCRRs. Due to the CAISO's very compressed CRR annual schedule, SCE is unable to identify which CRRs it intends to nominate for conversion into LTCRRs and obtain formal Commission approval through the application process. The Commission granted SCE authorization to acquire LTCRRs in

(Continued)

Resolution E-4122 in recognition that the CAISO's compressed annual CRR allocation process does not provide sufficient time for the Commission to review and approve SCE's specific nominations for LTCRRs.[13]

3. SCE May Participate in Annual and Monthly CRR Allocation and Auction Processes

SCE is authorized to participate in annual and monthly CRR allocation and auction processes to acquire CRRs to hedge its exposure to CAISO congestion costs and to offset long CRR positions. Currently, the MRTU design doesn't allow market participants to sell CRRs in the auction market. However, the CAISO allows LSEs to purchase counter-flow CRRs which act like a "sale" of CRRs in the auction. These counter-flow CRRs provide the opposite financial settlement as the original CRR and effectively cancel each other out. All SCE CRR allocation and auction awards that are in compliance with the upfront standards specified in this Appendix are per se reasonable. SCE may submit positive and negative value price bids in the CRR auction processes. In addition, SCE may obtain CRRs for positively correlated paths.

[13] Resolution E-4122 concluded that there was insufficient time for a formal approval process of SCE's LTCRR nominations at the conclusion of the CAISO's Tier One and Tier Two CRR awards. Subsequent to this Commission determination, the CAISO revised the schedule for its LTCRR award tier to follow Tier One and precede Tier Two.

(Continued)

4. SCE May Transact CRRs in the Secondary Market

SCE is authorized to pursue sales and purchases in the CRR secondary market. SCE shall consult with and inform PRG participants regarding all of SCE's activities in the secondary CRR market. SCE may use the same transaction processes that its AB 57 BPP authorizes SCE to use for bilateral energy transactions (*e.g.*, transact using brokers or exchanges), subject to providing a "strong showing" in its Quarterly Compliance Report (QCR), or through a Request for Offers (RFO) (if feasible). Among valid, competing offers for the same CRR, SCE shall select based on the better price (all else being equal). Locational spreads may also be purchased if related CRRs are not available.

5. CRR Hedging Risk

Prior to SCE participating in the CAISO's annual and monthly CRR allocation/auction processes, converting awarded CRRs to LTCRRs, and engaging in bilateral CRR transactions, SCE will evaluate the risks of obtaining CRRs for its candidate CRR paths. One risk of not having a CRR is that SCE may pay a high congestion cost to flow energy from its source to its sink. In contrast, one of the risks of having a CRR is that SCE may have to pay a high congestion cost if congestion counter-flows to the direction of that CRR.[14] SCE shall review its CRR valuation and

[14] This payment may be offset by SCE receiving a payment for flowing energy from its source to its sink counter-flow to the direction of congestion. However, if SCE's source is not available (*e.g.*, due to an outage), SCE would not receive an offsetting payment for the flow of energy.

(Continued)

risk analysis with its PRG on a prospective basis for the annual CRR allocation and auction process.

SCE shall employ different metrics to quantify its risk assessment of candidate CRRs, including, but not limited to:

1) Simulating random variables, such as load, hydro, gas prices, and outages; creating a distribution of congestion costs or CRR values for a period of time; and calculating metrics based on that distribution;
2) Creating a marginal cost of congestion duration curve indicating the number of hours (or percent of the time) that congestion exceeds a particular value and calculating metrics based on that duration curve;
3) Creating a distribution of the hourly dollar amounts received or paid for holding a CRR and calculating metrics based on that distribution;
4) Running various scenarios (or stress cases), such as for high or low loads, high or low gas prices, high or low generation/transmission outages, determining the expected congestion cost or CRR value for these scenarios over a period of time, and calculating the change in cost/value compared to the base case scenario;
5) Forecasting how congestion costs paid might vary depending on whether the resource at the CRR source location is must-take or dispatchable;
6) Estimating the risk mitigation achieved by the addition of candidate CRRs to the overall portfolio; or
7) Forecasting the potential amounts paid for holding a CRR during periods of counter-flow.

6. SCE's CRR Valuation Methodology

SCE will identify candidate CRRs for acquisition (or "sale" through the purchase of a counter-flow CRR when a CRR path is long) based on the location and magnitude of its resources

(Continued)

and loads. SCE will also identify additional candidate CRRs that are potentially positively correlated in value with CRRs of interest, so long as the correlation is a reflection of the physical realities of the grid. SCE will limit candidate CRRs to those CRRs with a source at which SCE reasonably expects to procure power.

For the overall portfolio and for each of the candidate CRRs, SCE will estimate the expected value for the relevant time period by using various methods, including the following (SCE is not required to use all of these methods and SCE may develop new or enhanced methods):

1) Running a model of the transmission network simulating the dispatch of generation to serve load and forecasting MCCs at CAISO nodes and hubs;
2) Obtaining a forecast of MCCs from one or more expert consulting firms;
3) Obtaining market price quotations (where available) at trading hubs;
4) Analyzing historical MCC data for trends, relationships, and correlations to forecast future MCCs; or
5) Averaging (or weight-averaging) forecasts of MCCs that were developed using two or more of the methodologies described above.

SCE will review with its PRG the methodologies it uses for valuation of its annual CRR transactions.

7. CRR Procurement Limits

SCE does not have a CRR procurement limit. Instead, SCE may only acquire CRRs that closely resemble its expected grid usage, both in the choice of source/sink combinations and in the duration of the CRR with respect to the length of its energy supply contracts and generation

(Continued)

ownership. As specified above, SCE may consider highly correlated CRRs to its candidate CRRs, provided the correlated CRR is a reflection of the physical realities of the grid.

8. Reporting and Accounting

SCE shall consult with its PRG prior to its participation in the CAISO's annual CRR allocation and auction processes, including the LTCRR nomination tier. SCE shall also consult with its PRG prior to transacting for any CRR having a term greater than one calendar quarter.

SCE is not required to consult with its PRG prior to its participation in the CAISO's monthly CRR processes, but shall be required to provide monthly reporting and conduct quarterly briefings. SCE shall provide its PRG participants a monthly summary report on its participation in the monthly CRR allocation and auction process within five business days after completion of the monthly CRR process. SCE's monthly PRG reporting shall provide information on each of SCE's CRR transactions, including source, sink, megawatt quantity, term, expected value, past performance (if applicable), bid price (for CRR auctions or secondary market transactions), and a description of the underlying energy supply arrangement that the CRR will hedge.

SCE shall also provide its PRG with information regarding SCE's bilateral transactions. SCE will submit this information to its PRG in one of two ways:

1. SCE will report secondary trades in a weekly report, submitted within two business days of the end of the reporting period (for example, a report from Thursday through Wednesday would need to be submitted by the Friday immediately following Wednesday), or

(Continued)

2. SCE will report secondary trades within two business days of the trade date, reporting each trade separately.

If a PRG participant requests a discussion of a secondary transaction regarding a CRR, SCE will discuss that transaction at the next appropriate PRG meeting.

SCE shall report all CRR transactions in its QCR. SCE's QCRs will contain for each CRR the source, sink, MW quantity, term, expected value, past performance (if applicable), bid price (for CRR auctions or secondary market transactions), and a description of the underlying energy supply arrangement that the CRR will hedge.

9. Revenues and Costs Related to CRR congestion

SCE records the revenues and costs related to congestion charges in its Energy Resource Recovery Account (ERRA). All entries recorded into SCE's ERRA balancing account, including CRR entries, will be examined by the Commission in its review of SCE's QCRs and annually in a review of the ERRA balancing account. Using the QCR and the ERRA review process, the Commission will determine whether SCE has complied with the upfront and achievable standards contained in its Commission-approved AB 57 BPP.

(Continued)

SOUTHERN CALIFORNIA EDISON COMPANY'S
PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN
APPENDICES

Appendix H

Convergence Bidding

(Continued)

Overview of SCE's Convergence Bidding Authorization

The Commission authorized SCE in D.10-12-034 to participate in convergence bidding (also referred to as "virtual bidding") in markets operated by the CAISO. The Commission's authorization specified three bidding strategies which SCE may utilize, subject to an annual stop loss limit.[15] SCE's authorized convergence bidding standards are specified below, and are permitted at all interties, nodes, and locations where utility resources or loads are located.[16]

1. Convergence Bidding Strategy 1: Generation Performance Risk and Utility Load Forecast Uncertainty Hedging

SCE is authorized to participate in convergence bidding to manage Real-Time price exposure resulting from unanticipated forced outages, derating of generating units, derating of transmission, or uncertain generation performance for resources scheduled by SCE in the CAISO's Day-Ahead market, and to hedge against load forecast uncertainty.[17] This strategy is also authorized for convergence bids related to long-start generation units.[18]

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15 SCE is not required to engage in convergence bidding activity.

16 *See* D.11-06-004, pp.3-4 and OP 1.

17 *See* D.10-12-034, p.23 and OP 2.

18 *See* D.11-06-004, pp.2-3 and OP 1.

(Continued)

2. Convergence Bidding Strategy 2: Renewable Resource Schedule and Hedging

For hedging the delivery uncertainty of intermittent resources, SCE is authorized to submit virtual supply bids in the CAISO's Day-Ahead market up to, but not exceeding, the amount of the Day-Ahead forecast of intermittent generation in the Day-Ahead market, followed by buying it back through the convergence sale in the CAISO Real-Time market.[19]

3. Convergence Bidding Strategy 3: Defensive Bidding Against Market Dynamics

SCE is authorized to participate in defensive convergence bidding in the CAISO's Day-Ahead and Real-Time energy markets to mitigate harms from market manipulation or other unintended market dynamics. SCE will report its use of defensive convergence bidding on a case-by-case basis with actual market and settlement data, and not just using hypothetical scenarios showing how engaging in convergence bidding protects customers. SCE's report will explain how its defensive convergence bidding strategies were intended to protect its customers from avoidable risks at identified locations. [20]

19 *See* D.10-12-034, p.24 and OP 3.

20 *See id.* at p.27 and OP 4.

(Continued)

4. Annual Stop-Loss

SCE's convergence bidding participation in the CAISO's Day-Ahead and Real-Time energy markets is subject to an absolute stop-loss limit of $20 million. The stop-loss limit is calculated on a rolling 365-day basis, and exceeding the stop-loss limit will suspend SCE's authorization to participate in convergence bidding until SCE files a Tier 3 Advice Letter and gains Commission approval to resume convergence bidding. The Advice Letter must contain, at a minimum: (1) an explanation for why SCE exceeded the stop-loss limit; (2) an explanation of what actions or changes to its bidding activity SCE will implement to ensure that future convergence bidding will not continue to lose customer funds; and (3) an explanation for why SCE's authority to engage in convergence bidding should be reinstated.[21]

5. Reporting and Process Requirements

SCE is subject to the following reporting requirements.

a) SCE will, within one business day of its receipt of notice, provide written notice to the Commission's Executive Director, the Director of Energy Division (ED), and the General Counsel of: [22]

(1) notice from the CAISO or its Department of Market Monitoring that the SCE or its scheduling coordinator is the subject of an investigation pursuant to the CAISO Tariff, including Section 37.8.4;

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21 *See id.* at pp.32-34 and OP 6.

22 *See id.* at pp.9-40 and OP 5.

(2) notice from the CAISO that the conduct of SCE or its scheduling coordinator conduct has been referred to the Federal Energy Regulatory Commission by the CAISO pursuant to the CAISO Tariff, including Section 37.8.2; or

(3) notice from the CAISO that SCE or its scheduling coordinator's convergence bidding trading has been suspended or limited by the CAISO.

b) SCE will provide a set of information on its convergence bidding activity to the Commission in its Quarterly Compliance Reports. The report will cover SCE's convergence bidding activity in the CAISO's Day-Ahead and Real-Time energy markets for each calendar month, and will at a minimum include the following information: [23]

(1) A list of each cleared convergence bid, containing the hour, location, volume, and justification for the transaction;

(2) A list of the Day-Ahead and Hour Ahead prices corresponding with each convergence bid;

(3) For each day the gains or losses, in dollars, as a result of convergence bidding;

(4) For that month, and any past months during the calendar year in which convergence bids were transacted, a monthly total of volume, gains or losses (in dollars), the number of times each strategy was employed, and the number of bids conducted outside of that IOU's service territory;

(5) The approved convergence bidding strategies utilized during that time period;

(6) Qualitative analysis of convergence bidding impacts upon other related products, such as CRRs; and

23 *See id.* at pp.41-42 and OP 7.

(Continued)

(7) A list of any affiliates who have or are registered with the CAISO to participate in convergence bidding.

c) SCE will provide to its Procurement Review Group (PRG) a review of SCE's convergence bidding strategies, performance, and market analysis at each of its quarterly PRG meetings, including information contained in Section 5.(b) above.[24]

6. Revenues and Costs Associated with Convergence Bidding

SCE records the revenues and costs related to its convergence bidding activity in its ERRA balancing account.[25] All entries recorded into SCE's ERRA balancing account, including convergence bidding entries, will be examined by the Commission in its review of SCE's QCRs and annually in a review of the ERRA balancing account. Using the QCR and the ERRA review process, the Commission will determine whether SCE has complied with the upfront and achievable standards contained in its Commission-approved AB 57 BPP.

24 *See id.* at p.42 and OP 7 and 8.

25 *See id.* at pp.29-30 and OP 1.

(Continued)

SOUTHERN CALIFORNIA EDISON COMPANY'S
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APPENDICES

Appendix I

Contract Limitations With Power Generation Facilities Utilizing Once-Through Cooling

(Continued)

Contract Limitations With Power Generation Facilities Utilizing Once-Through Cooling

SCE is authorized to sign power purchase agreements (PPAs) with power plants using once-through cooling (OTC), but those agreements may not commit to purchases beyond the applicable State Water Resources Control Board (SWRCB) compliance deadline, and those agreements must be submitted to the Commission for approval via a Tier 3 Advice Letter for contracts of more than two years but less than five years, or via an application for contracts with a duration of five years or more. In addition, the applicable RFO or other solicitation evaluation must take into consideration the plant's use of OTC.

If such agreements terminate one year or less prior to the applicable SWRCB compliance deadline, the advice letter or application must specifically show how the agreement helps facilitate compliance with the SWRCB policy regarding OTC.

SCE contracts with facilities utilizing OTC may extend beyond the SWRCB OTC compliance date, but only if such contracts: (1) Allow for utility purchase or receipt of power generated by a unit using non-compliant OTC only up to the SWRCB OTC policy compliance date in effect on the date the contract is signed. The contract shall not allow SCE to continue to purchase or receive power generated using non-compliant OTC beyond that date even if the SWRCB extends the compliance date; (2) Protect utility customers against stranded costs; (3) Protect customers against the risk of future unspecified cost increases resulting from increases in the cost of the generation unit compliance with the SWRCB OTC policy. For SCE to recover such

(Continued)

cost increases from customers, it must obtain approval from the Commission; (4) Are consistent with a need authorization from the System Track of the LTPP proceeding; and (5) Are consistent with other procurement rules, including D.12-04-046's requirement to file either a Tier 3 Advice Letter or an application.

Any such advice letter or application must show compliance with all relevant SWRCB policies and regulations, and show how the contract provides or facilitates cost-effective and reliable service.

(Continued)

Southern California Edison

Rosemead, California (U 338-E)

SOUTHERN CALIFORNIA EDISON COMPANY'S

PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN

APPENDICES

Appendix J

Valuation and Risk Management Considerations

(Continued)

Valuation and Risk Management Considerations

1. Sample Cost Adders for RFO Evaluations

a) Debt Equivalence

Debt equivalence costs reflect the capital structure changes SCE may be required to implement in order to maintain the same credit rating from credit rating agencies. The debt equivalence risk factor was previously set at 20% in accordance with D.04-12-048.[26] All offers are assessed the applicable debt equivalence cost, if any, and discounted to a present value.

b) Collateral Cost Adder

A cost adder will be assessed for any counterparty who requires SCE to post collateral, to reflect the cost of posting to SCE. This cost adder has two components. The first component is assessed if the counterparty only requires SCE to post in case of a downgrade, and consists of the cost of maintaining a credit line of suitable size for that contract. The second component is charged if the counterparty requires SCE to post collateral due to adverse market movements that cause the contract to be out of the money.

[26] D.04-12-048, pp.200, 221.

(Continued)

c) GHG Cost

Offers that result in a GHG compliance obligation for SCE will be assessed a cost adder based on the amount of GHG compliance instruments forecasted to be required multiplied by a forecast of GHG compliance prices.

d) Credit Risk Cost Adder (CRCA)

Counterparties not meeting SCE's preferred credit terms are subject to a cost adder to capture the additional credit risk posed by the party. A CRCA will be assessed for any contract in which the counterparty does not agree to post collateral up to SCE's desired limit. Components of this calculation include the potential future exposure on the contract, the net exposure over and above the collateral that the counterparty has agreed to post, and the credit rating of the counterparty.

2. Example and Format of a Risk Report

An example of TEVaR results is provided in the following Table J-1and Figure J-1.

(Continued)

Table J-1
TEVaR Results
(Confidential)

Rolling Period [1]	Actual Horizon [2]	Hedges In EV (PV $MM) [3]	Hedges In StDev (PV $MM) [4]	Hedges In TEVaR-95 (PV $MM) [5]	Hedges Out EV (PV $MM) [6]	Hedges Out StDev (PV $MM) [7]	Hedges Out TEVaR-95 (PV $MM) [8]
12 Month	Sep-14-Aug-15	[redacted]					
Month #1	Sep-14						
Month #2	Oct-14						
Month #3	Nov-14						
Month #4	Dec-14						
Month #5	Jan-15						
Month #6	Feb-15						
Month #7	Mar-15						
Month #8	Apr-15						
Month #9	May-15						
Month #10	Jun-15						
Month #11	Jul-15						
Month #12	Aug-15						
Quarter #5	Sep-15 - Nov-15						
Quarter #6	Dec-15 - Feb-16						
Quarter #7	Mar-16 - May-16						
Quarter #8	Jun-16 - Aug-16						
Year #3	Sep-16 - Aug-17						
Year #4	Sep-17 - Aug-18						
Year #5	Sep-18 - Aug-19						
2015	Jan-15 - Dec-15						
2016	Jan-16 - Dec-16						
2017	Jan-17 - Dec-17						
2018	Jan-18 - Dec-18						
5 Years	Sep-14 - Aug-19						

All calculations performed using SCE's Risk Assessment & Planning Tool ("ERAPT") using forward prices dated 07/22/2014
[1]: Rolling time periods specified in CPUC order D.03-12-062
[2]: Range of months associated with rolling periods in [1]
[3]-[5]: Expected value, standard deviation*, and 95 percentile TEVaR for SCE's market sensitive procurement cost.
[6]-[8]: Expected value, standard deviation*, and 95 percentile TEVaR for SCE's market sensitive procurement cost Absent hedges entered into in July 2014
* The variance is the square of the standard deviation.

(Continued)

Figure J-1
5 Year NPV Procurement Cost Distribution for July 2014 Portfolio Risk Report, Forward Prices as of 07/22/2014 (Confidential)

The columns in the reports are defined as follows:

- Rolling Period: This provides the time frame associated the reported metrics.

(Continued)

- Actual Horizon: This provides the beginning and end month associated with the reporting metrics.
- EV: This is the expected value of SCE's market sensitive procurement costs.
- StDev: This provides the standard deviation of SCE's market sensitive procurement costs.
- TEVaR 95: This provides the difference between the 95th percentile procurement costs and the expected procurement cost.

Note that the table provides two sets of results, one labeled "hedges in" and one labeled "hedges out." The results in the "hedges in" set correspond to all the positions in the SCE portfolio. The results in the "hedges out" set correspond to the portfolio of the "hedges in" set with the forward market positions (purchases and sales) taken during the reporting month removed from the portfolio. In the above case, the "hedges in" and "hedges out" portfolio are the same.

3. SCE's Customer Risk Tolerance

The Commission has adopted a Customer Risk Tolerance (CRT) rate equivalent to 10% of the Energy Resource Revenue Account (ERRA) portion of the utility's system average rate at the time of submittal of the conformed bundled procurement plan. Based on SCE's current bundled system average rate of 16.7 cents/kWh and the ERRA portion of 6.9 cents/kWh, a 10% risk tolerance factor yields a CRT of 0.69 cents/kWh.

(Continued)

Southern California Edison

Rosemead, California (U 338-E)

SOUTHERN CALIFORNIA EDISON COMPANY'S

PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN

APPENDICES

Appendix K

Changes Since Previous Procurement Plan and Decisions Pending or Recently Issued Related to Procurement

(Continued)

SOUTHERN CALIFORNIA EDISON COMPANY'S
PROPOSED 2014 AB 57 BUNDLED PROCUREMENT PLAN APPENDICES

I. Changes Since Previous AB 57 BPP

SCE's previous AB 57 BPP was its 2010 Conformed AB 57 BPP submitted in Advice 2713-E-B on July 23, 2012, which was approved by Resolution E-4542, effective October 11, 2012. Since July 23, 2012, SCE submitted eight Advice Letters that the Commission approved, thereby updating its AB 57 BPP. These Advice Letters are summarized below. SCE's 2014 Conformed AB 57 BPP herein, approved in the 2014 LTPP proceeding, captures all of these modifications.

- **Advice 2823-E** (submitted December 11, 2012) updated the electricity and natural gas ratable rates and position limits in SCE's AB 57 BPP covering the years 2012 through 2022. The ED approved this Advice Letter on February 7, 2013, effective January 1, 2013.
- **Advice 2824-E** (submitted December 11, 2012) updated the GHG rates and limits in SCE's AB 57 BPP covering the years 2012 through 2022. The ED approved this Advice Letter on March 4, 2013, effective February 19, 2013.
- **Advice 2925-E** (submitted July 19, 2013) added two brokers. The ED approved this Advice Letter on September 30, 2013, effective August 19, 2013.
- **Advice 2957-E** (submitted October 31, 2013) updated the electricity and natural gas ratable rates and position limits in SCE's AB 57 BPP covering the years 2014 through 2022. The ED approved this Advice Letter on December 3, 2013, effective December 3, 2013.

(Continued)

- **Advice 2958-E** (submitted October 31, 2013) updated the GHG rates and limits in SCE's AB 57 BPP covering the years 2014 through 2022. The ED approved this Advice Letter on January 15, 2014, effective January 1, 2014.
- **Advice 2976-E** (submitted November 26, 2013) added a new exchange, clarified portfolio risk assessment reporting and credit terms, and implemented ministerial corrections. The ED approved this Advice Letter on December 19, 2013, effective December 26, 2013.
- **Advice 3035-E** (submitted May 8, 2014) updated SCE's CRT level for year 2014. The ED approved this Advice Letter on July 2, 2014, effective May 8, 2014.
- **Advice 3104-E** (submitted September 25, 2014) added two additional brokers to SCE's list of authorized brokers and exchanges. The Advice Letter is awaiting the ED's approval.

II. Decisions Pending or Recently Issued Related to Procurement

1. 2012 LTPP Proceeding (R.12-03-014)

On March 22, 2012, the Commission opened R.12-03-014 to address issues related to the reliable and cost-effective electricity supply in California through integration and refinement of a comprehensive set of procurement policies, practices, and procedures underlying long-term procurement plans. In the May 17, 2012 Scoping Ruling, the Commission established three major tracks to be addressed: (1) Local Reliability (Track 1); (2) System Needs (Track 2); and (3) Procurement Rules and Bundled Procurement (Track 3). Subsequently, the Commission issued a

(Continued)

revised Scoping Ruling on May 21, 2012 that added an additional track to the proceeding, Track 4, which considered the local reliability impacts of a potential long-term outage at the SONGS generating units.

In the Track 1 D.13-02-015, the Commission authorized SCE to procure up to 1,800 MW in the Los Angeles (LA) Basin and up to 290 MW in the Moorpark area to meet LCR. SCE was ordered to procure at least 1,000 MW of gas-fired generation, at least 150 MW of preferred resources and at least 50 MW of storage in the LA Basin. The remaining authorized procurement amounts were to be procured from any resources. Subsequent to SCE's LCR RFO, SCE filed its applications for approval of the LCR contracts with the Commission on November 21, 2014.

In the Track 4 D.14-03-004, the Commission ordered SCE to procure an additional 500 MW to 700 MW with at least 400 MW of preferred resources and the remaining from any source. SCE was authorized to use the similar procurement process approved in Track 1 to procure capacity for the purposes of Track 4.

In the Track 3 D.14-02-040, the Commission made several procurement rule changes for utility procurement of electricity in California. SCE's 2014 Conformed AB 57 BPP herein, approved in the 2014 LTPP proceeding, incorporates these new directives.

(Continued)

2. GHG Cost Proceeding (R.11-03-012)

On March 24, 2011, the Commission opened R.11-03-012 to address issues related to GHG costs and revenues resulting from the implementation of California's GHG cap-and-trade program pursuant to AB 32. The September 1, 2011 Scoping Ruling established three tracks in R.11-03-012 to address the following issues: (1) allocation of revenue from the auction of greenhouse gas allowances (Track 1); (2) allocation of revenues from the sale of Low-Carbon Fuel Standard (LCFS) credits (Track 2); and (3) GHG product procurement and revenue allocation for gas utilities (Track 3).

3. Energy Storage Proceeding (R.10-12-007)

On December 16, 2010, the Commission opened R.10-12-007 to implement the provisions of AB 2514 (Stats. 2010, ch. 469). AB 2514 directed the Commission to determine appropriate targets for each LSE to procure viable and cost-effective energy storage systems (ESS) and set dates for these targets to be achieved.

D.13-10-040 on Phase 2 established a cumulative target of 1,325 MW of energy storage to be procured by Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas and Electric Company by 2020, with installations required no later than the end of 2024, and set a schedule for procurement of energy storage. SCE is required to procure 580 MW (including utility-owned energy storage) of the 1,325 MW authorized by 2020. SCE intends to

(Continued)

count the 50 MW of storage authorized in D.14-02-040 in the LTPP proceeding towards its storage target.

4. RA Proceeding (R.11-10-023)

The Commission opened R.11-10-023 to oversee the RA program, make necessary and appropriate refinements to the program, and establish local procurement obligations beginning with the 2013 compliance year. The proceeding was divided into three phases. The Commission issued D.12-06-025 on Phase 1, which adopted LCRs for 2013, made minor revisions to rules governing how resources count toward meeting RA requirements, added a new maximum cumulative capacity category to address demand response and made other minor ministerial changes. The Commission issued D.13-06-024 on Phase 2, which adopted LCR for 2014, adopted a flexible RA program for 2015 through 2017, and made other minor ministerial changes. The Commission issued D.14-06-050 on Phase 3, which adopted LCRs for 2015, adopted a flexible RA requirement for 2015, made revisions to the flexible RA program for 2015 through 2017, clarified how the IOUs as the procurement entity for CAM allocated resource are to utilize those resources within the RA program, required entities using demand response to meet RA requirements to file evidence demonstrating performance of demand response resources annually, continued with the use of the "exceedance" methodology for wind and solar resources for 2015, and made minor ministerial changes to the RA program.

(Continued)

5. RPS Proceeding (R.11-05-005)

In this proceeding, the Commission is considering IOUs' 2014 RPS procurement plans (RPS Plans). On May 21, 2014, the Commission issued a ruling revising the Renewable Net Short (RNS) Methodology to be utilized in all IOUs' RPS Plans. On June 4, 2014, all IOUs, including SCE, filed their RPS Plans and included their updated RNS based on the new adopted methodology. SCE is anticipating a decision on its 2014 RPS Plan in late 2014.

In addition to approval of the RPS Plans, R.11-05-005 has implemented the Renewable Auction Mechanism (RAM) program, a standard contracting program for renewable projects 3 to 20 MW in size through D.10-12-048 and also the Renewable Market Adjusting Tariff (Re-MAT), a Public Utility Regulatory Policies Act of 1978 (PURPA) feed-in tariff program for QF projects up to 3 MW in size pursuant to Senate Bills (SB) 380, 32, and 2 1X and D.12-05-035 and D.13-05-034. Additionally, the Commission has implemented rules in the proceeding relating to the 33% RPS program pursuant to SB 2 1X in D.11-12-020, D.11-12-052, and D.12-06-038.

The Commission also issued D.09-06-049 authorizing SCE to establish a Solar Photovoltaic Program (SPVP) for solar rooftop and ground-mounted projects greater than 500 kWdc and up to 10 MWdc. In accordance with D.14-06-048's directive that SCE shall conduct a fourth SPVP RFO to solicit all of the remaining uncontracted capacity from independent power producers, SCE plans to launch a fourth SPVP RFO in the fourth quarter of 2014.

(Continued)

6. CHP Settlement

Since November 2011, SCE has also offered and now administers PPAs entered into pursuant to the Combined Heat and Power (CHP) Program Settlement Agreement ("CHP Settlement," "QF Settlement," or "Settlement"), adopted by the Commission in D. 10-12-035. This Settlement develops a State CHP Program with the intent to transition from the prior PURPA program to a market-based state-administered program for CHP projects above 20 MW. This program is governed by a set of provisions referred to here as the CHP Settlement Term Sheet (Term Sheet). Pursuant to one of the conditions precedent in the Settlement, on June 16, 2011, the FERC granted the California Investor Owned Utilities' (IOUs')[27] §210(m) application to terminate the PURPA must-take obligation for QFs above 20 MW.[28]

The Settlement also established a QF Standard Offer Contract (QF SOC) for QFs 20 MW or less. The QF SOC is a PURPA contract established by the Commission pursuant to its authority to implement PURPA for QFs 20 MW and under. Additionally, the Settlement created two main market-based agreements for CHP projects. The first is the Transition PPA, which is available to all QF CHP units with an existing contract with SCE as of November 23, 2011 (Settlement Effective Date). These contracts are required to expire by June 30, 2015. As of June 7, 2013, the

27 California Investor-Owned Utilities include SCE, Pacific Gas and Electric Company, and San Diego Gas and Electric Company.

28 135 FERC ¶61,234.

(Continued)

Transition PPA was deemed by the FERC as a PURPA PPA.[29] The second agreement is a Standard PPA signed pursuant to the CHP Settlement's RFO process (CHP RFO PPA). This contract is not a PURPA contract. In addition to these PPAs, SCE also offers contracts to qualifying CHP projects of 20 MW or less pursuant to AB 1613; like the QF SOC, this program and its associated contracts are administered per the requirements of PURPA, which remains in effect in California for QFs of 20 MW or less.[30]

29 143 FERC ¶ 61,222.

30 Adopted in D.09-12-042.

(Continued)

SOUTHERN CALIFORNIA EDISON COMPANY'S
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Appendix L

Organizational Structure of SCE's Power Procurement Business Area

(Continued)

SOUTHERN CALIFORNIA EDISON COMPANY'S
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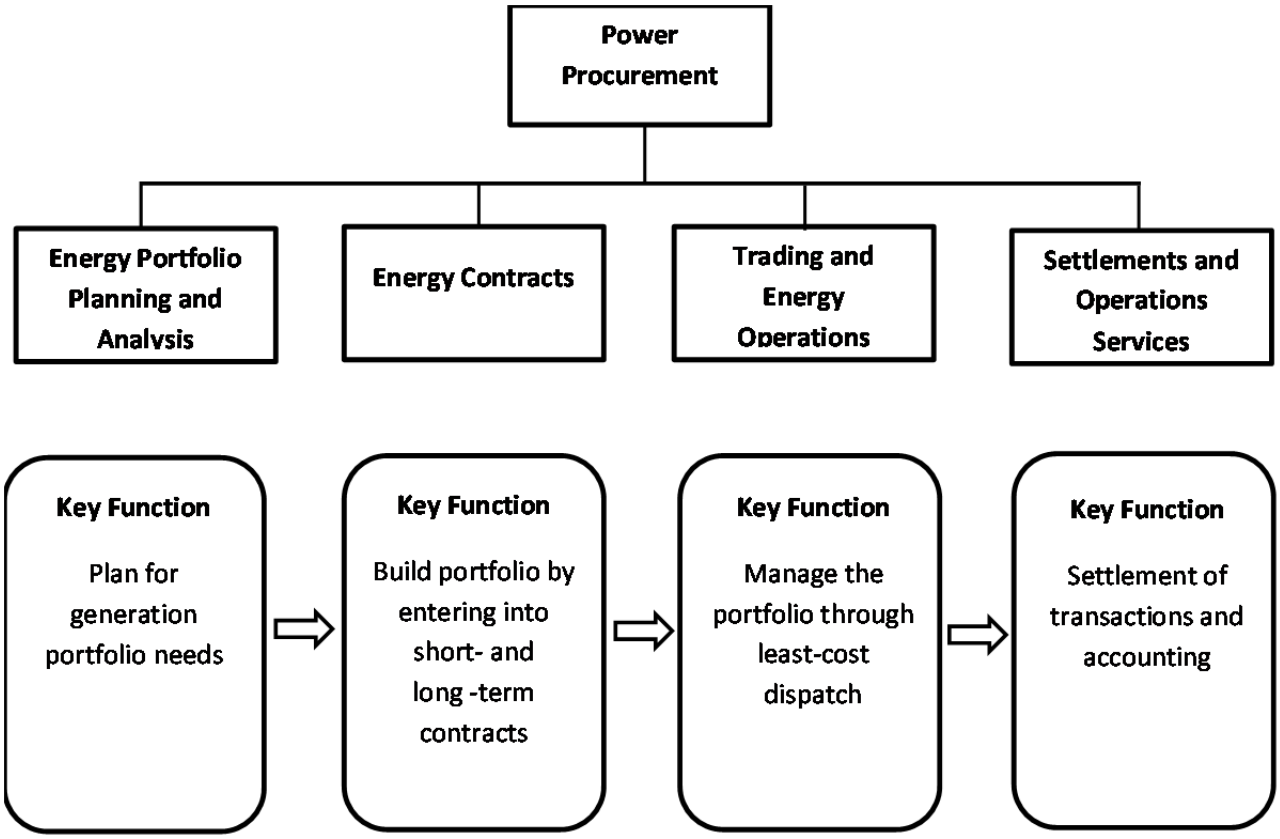
Organizational Structure of SCE's Power Procurement Business Area

As it relates to bundled procurement, SCE's Power Procurement business area ensures that SCE's bundled customers have enough electricity to meet their needs through the output of SCE-owned generation plants and the purchase of fuel and electricity from wholesale energy markets. Power Procurement engages in various power purchases from independently-owned conventional and renewable generators, and also conducts electricity, gas, and emissions trading. Power Procurement is presently comprised of four departments: (1) Portfolio Planning and Analysis, (2) Energy Contracts (3) Trading and Energy Operations, and (4) Settlements and Operations Services. The following is an organization chart for SCE's Power Procurement business area, followed by a brief discussion of the primary responsibilities of each department.

(Continued)



B. Portfolio Planning and Analysis

Portfolio Planning and Analysis is responsible for providing the forecasts, analysis, and valuation support needed for Power Procurement to meet SCE's bundled customer demand. In addition, the Portfolio Planning and Analysis department analyzes and evaluates new contract offers and proposed amendments to existing contracts in coordination with the Energy Contracts

(Continued)

department. Portfolio Planning and Analysis is responsible for providing the analytical support required to conduct solicitations and procure energy products from generation resources to meet customer needs and regulatory and legislative requirements. Portfolio Planning and Analysis is also responsible for assisting with integrating Demand Response programs into California's wholesale power markets. Power Procurement performs these activities to ensure customers receive the highest value possible.

C. Energy Contracts

Through competitive solicitations and bilateral negotiations, Energy Contracts initiates and administers energy, capacity, and emissions contracts needed to serve SCE's bundled customers, and, in certain cases, direct access customers. Energy Contracts is also responsible for negotiating and executing master trading agreements and for administering all energy-related contracts through their lifecycle on behalf of SCE's customers.

D. Trading and Energy Operations

The Trading and Energy Operations department includes the following three divisions: (1) Asset Optimization and Trading, (2) Energy Operations, and (3) CAISO Market Implementation. The functions of each division are discussed below.

Asset Optimization and Trading is comprised of four organizational units, (1) Resource Optimization, (2) Short-Term Planning, (3) Power Trading, and (4) Gas and Emissions Trading.

(Continued)

This division is responsible for optimizing SCE's portfolio of assets, preparing the daily plan to meet load and executing short-term trades for power and gas as well as GHG and sulfur dioxide emissions credits.

Energy Operations is comprised of the following four groups: (1) Day-Ahead Operations, (2) Real-Time Operations, (3) Trading and Energy Operations Support, and (4) Renewables Resource Integration. The primary responsibilities of Energy Operations are to: (i) prepare, validate, and submit electricity supply and demand bids and resource schedules to the CAISO; (ii) schedule and manage SCE's power transactions with entities outside the CAISO; (iii) transact in over-the-counter markets, as necessary, to purchase or sell hour-ahead power products; and (iv) enable dispatch of SCE's resource portfolio as necessary based on changing prices, system conditions, and CAISO orders, consistent with contract terms and operating constraints. In discharging these responsibilities, Energy Operations personnel continuously monitor the status of SCE's generation and system conditions and maintain essential communication with the CAISO on a seven-day-per-week (Day-Ahead Operations groups) and twenty-four-hour, seven-day-per-week (Real-Time Operations groups) basis.

CAISO Market Implementation is primarily focused on assessing and preparing Power Procurement's operations for new CAISO market changes. CAISO Market Implementation assesses the CAISO's market policy changes against SCE's systems and processes and determines the impact and feasibility of such changes. CAISO Market Implementation provides technical and policy analysis of market design changes and ensures SCE readiness to implement these changes.

(Continued)

E. Settlements and Operations Support

The Settlements and Operations Services department's responsibilities include information and data management of contracts, business process services for all activities that support Power Procurement, and all administrative duties.

In addition, this department of Power Procurement is responsible for ensuring the proper settlement of all Energy Products contracts for Power Procurement. The settlement process ensures that all contract and market payments and receipts are in accordance with the terms of the applicable contract or tariff provisions associated with the underlying transactions.

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